UNOCAL CORP
Form 10-Q
August 11, 2003

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2003

OR

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

For the transition period from ______________ to ____________________

Commission file number 1-8483

UNOCAL CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	95-3825062
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2141 ROSECRANS AVENUE, SUITE 4000, EL SEGUNDO, CALIFORNIA 90245
(Address of principal executive offices)
(Zip Code)

(310) 726-7600
(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 Act). Yes X No _______

Number of shares of Common Stock, $1 par value, outstanding as of July 31, 2003: 258,344,422

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GLOSSARY

Below are certain definitions of key terms that may be in use in this Form 10-Q report.

M	Thousand	Bbl	Barrels
MM	Million	Cf/d	Cubic feet per day
B	Billion	Cfe/d	Cubic feet of gas equivalent per day
T	Trillion	Btu	British thermal units
CF	Cubic feet	DD&A	Depreciation, depletion and amortization
BOE	Barrels of oil equivalent	NGLs	Natural gas liquids
Liquids	Crude oil, condensate and NGLs		
Bbl/d	Barrels per day		

- API Gravity is a measurement of the gravity (density) of crude oil and other liquid hydrocarbons by a system recommended by the American Petroleum Institute ("API"). The measuring scale is calibrated in terms of "API degrees." The higher the API gravity, the lighter the oil.

- Bilateral institution refers to a country specific institution, which lends funds primarily to promote the export of goods from that country. Examples of bilateral institutions are Ex-Im (U.S.), Hermes (Germany), SACE (Italy), COFACE (France), and JBIC (Japan).

- BOE is a term used to quantify oil and natural gas amounts using the same measurement. Gas volumes are converted to barrels of oil equivalent on the basis of energy content, where the volume of natural gas that when burned produces the same amount of heat as a barrel of oil (6,000 cubic feet of gas equals one barrel of oil equivalent).

- British Thermal Units ("Btu") is a standardized unit of measure for energy, equivalent to the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. Ten thousand MMBtu (million Btu) is the standard volume for exchange traded derivative contracts, the approximate heat content of ten thousand Mcf (thousand cubic feet) of natural gas.

- Delineation or appraisal well is a well drilled in an unproven area adjacent to a discovery well to define the boundaries of the reservoir.

- Development well is a well drilled within the proved area of an oil or natural gas reservoir to a depth of a stratigraphic horizon known to be productive.

- Dry hole is a well incapable of producing hydrocarbons in sufficient commercial quantities to justify future capital expenditures for completion and additional infrastructure.

- Economic interest method pursuant to production sharing contracts is a method by which the Company's share of the cost recovery revenue and the profit revenue is divided by market oil and gas prices and represents the volume that the Company is entitled to. The lower the commodity price, the higher the volume entitlement, and vice versa.

- Exploratory well is a well drilled to find and produce oil or natural gas reserves that is not a development well.

- Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in," while the interest transferred by the assignor is a "farm-out."

- Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

- Floating Production Storage and Offloading ("FPSO") technology refers to the use of a vessel that is stationed above or near an offshore oil field. Produced fluids from subsea completion wells are brought by flowlines to the vessel where they are separated, treated, stored and then offloaded to another vessel for transportation.

- Gross acres or gross wells are the total acres or wells in which a working interest is owned.

- Hydrocarbons are organic compounds of hydrogen and carbon atoms that form the basis of all petroleum products.

o Lifting is the amount of liquids each working-interest partner takes physically. The liftings may actually be more or less than actual entitlements that are based on royalties, working interest percentages, and a number of other factors.

o Liquefied Natural Gas ("LNG") is a gas, mainly methane, which has been liquefied in a refrigeration and pressure process to facilitate storage and transportation.

o Liquefied Petroleum Gas ("LPG") is a mixture of butane, propane and other light hydrocarbons. At normal temperature it is a gas, but when cooled or subjected to pressure it can be stored and transported as a liquid.

o Multilateral institution refers to an institution with shareholders from multiple countries that lends money for specific development reasons. Examples of multilateral institutions are International Finance Corporation ("IFC"), European Bank for Reconstruction and Development ("EBRD"), and Asian Development Bank ("ADB").

o Natural Gas Liquids ("NGLs") are primarily ethane, propane, butane and natural gasolines which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature.

o Net acreage and net oil and gas wells are obtained by multiplying gross acreage and gross oil and gas wells by the Company's working interest percentage in the properties.

o Net pay is the amount of oil or gas saturated rock capable of producing oil or gas.

o Production Sharing Contract ("PSC") is a contractual agreement between the Company and a host government whereby the Company, acting as contractor, bears all exploration costs, development and production costs in return for an agreed upon share of the proceeds from the sale of production.

o Producible well is a well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

o Prospective acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas.

o Proved acreage is acreage that is allocated to producing wells or wells capable of production or to acreage that is being developed.

o Reservoir is a porous and permeable underground formation containing oil and/or natural gas enclosed or surrounded by layers of less permeable rock and is individual and separate from other reservoirs.

o Subsea tieback is a well with the wellhead equipment located on the bottom of the ocean.

o Take-or-Pay is a type of contract clause where specific quantities of a product must be paid for, even if delivery is not taken. Normally, the purchaser has the right in following years to take product that had been paid for but not taken.

o Trend or Play is an area or region of concentrated activity with a group of related fields and prospects.

- Working interest is the percentage of ownership that the Company has in a joint venture, partnership, consortium, project or acreage.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONSOLIDATED EARNINGS (UNAUDITED) UNOCAL CORPORATION

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Millions of dollars except per share amounts	2003	2002	2003	2002
Revenues				
Sales and operating revenues	$ 1,564	$ 1,361	$ 3,339	$ 2,396
Interest, dividends and miscellaneous income (loss)	9	8	20	20
Gain (loss) on sales of assets	47	(1)	50	1
Total revenues	1,620	1,368	3,409	2,417
Costs and other deductions				
Crude oil, natural gas and product purchases	536	428	1,182	723
Operating expense	325	324	619	623
Administrative and general expense	87	37	138	80
Depreciation, depletion and amortization	255	255	515	479
Asset impairments	3	21	3	21
Dry hole costs	10	13	81	41
Exploration expense	88	61	143	120
Interest expense	36	43	74	94
Property and other operating taxes	21	18	43	34
Distributions on convertible preferred securities of subsidiary trust	8	8	16	16
Total costs and other deductions	1,369	1,208	2,814	2,231
Earnings from equity investments	53	51	96	88
Earnings from continuing operations before income taxes and minority interests	304	211	691	274
Income taxes	133	95	301	135
Minority interests	2	3	4	4
Earnings from continuing operations	169	113	386	135
Earnings from discontinued operations	8	1	8	1
Cumulative effects of accounting changes (a)	-	-	(83)	-
Net earnings	$ 177	$ 114	$ 311	$ 136
Basic earnings per share of common stock (b)				
Continuing operations	$ 0.66	$ 0.46	$ 1.50	$ 0.55

Net earnings	$ 0.69	$ 0.46	$ 1.21	$ 0.55
Diluted earnings per share of common stock (c)				
Continuing operations	$ 0.65	$ 0.46	$ 1.47	$ 0.55
Net earnings	$ 0.68	$ 0.46	$ 1.20	$ 0.55
Cash dividends declared per share of common stock	$ 0.20	$ 0.20	$ 0.40	$ 0.40

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CONSOLIDATED BALANCE SHEET UNOCAL CORPORATION

Millions of dollars	At June 30, 2003 (a)	At December 31, 2002
Assets		
Current assets		
Cash and cash equivalents	$ 363	$ 168
Accounts and notes receivable - net	1,000	994
Inventories	101	97
Deferred income taxes	120	90
Other current assets	32	26
Total current assets	1,616	1,375
Investments and long-term receivables - net	1,074	1,044
Properties - net (b)	8,327	7,879
Goodwill	129	122
Deferred income taxes	247	210
Other assets	143	130
Total assets	$ 11,536	$ 10,760
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 1,050	$ 1,024
Taxes payable	220	223
Dividends payable	51	51
Interest payable	45	50
Current portion of environmental liabilities	121	113
Current portion of long-term debt and capital leases	232	6
Other current liabilities	176	165
Total current liabilities	1,895	1,632
Long-term debt and capital leases	2,744	3,002
Deferred income taxes	677	593
Accrued abandonment, restoration and environmental liabilities	917	622
Other deferred credits and liabilities	860	816
Minority interests	276	275
Commitments and contingencies - Note 13		
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	522	522

Common stock ($1 par value, shares authorized: 750,000,000 (c))	269	269
Capital in excess of par value	973	962
Unearned portion of restricted stock issued	(16)	(20)
Retained earnings	3,229	3,021
Accumulated other comprehensive income	(364)	(486)
Notes receivable - key employees	(35)	(37)
Treasury stock - at cost (d)	(411)	(411)
Total stockholders' equity	3,645	3,298
Total liabilities and stockholders' equity	$ 11,536	$ 10,760

CONSOLIDATED CASH FLOWS (UNAUDITED) UNOCAL CORPORATION

Millions of dollars	For the Six Months Ended June 30, 2003	2002
Cash Flows from Operating Activities		
Net earnings	$ 311	$ 136
Adjustments to reconcile net earnings to net cash provided by operating activities		
Depreciation, depletion and amortization	515	479
Asset impairments	3	21
Dry hole costs	81	41
Amortization of exploratory leasehold costs	71	45
Deferred income taxes	40	(17)
Gain on sales of assets	(50)	(1)
Gain on disposal of discontinued operations	(13)	(2)
Pension expense	42	13
Restructuring provisions net of payments	27	19
Cumulative effect of accounting changes	83	-
Other	41	(72)
Working capital and other changes related to operations		
Accounts and notes receivable	6	18
Inventories	(4)	(9)
Accounts payable	26	(1)
Taxes payable	(3)	(4)
Other	(91)	(40)
Net cash provided by operating activities	1,085	626
Cash Flows from Investing Activities		
Capital expenditures (includes dry hole costs)	(917)	(830)
Proceeds from sales of assets	191	45
Proceeds from sale of discontinued operations	-	2

Net cash used in investing activities	(726)	(783)
Cash Flows from Financing Activities		
Long-term borrowings	79	440
Reduction of long-term debt and capital lease obligations	(143)	(229)
Minority interests	(3)	(4)
Proceeds from issuance of common stock	10	19
Dividends paid on common stock	(103)	(98)
Other	(4)	-
Net cash provided by (used in) financing activities	(164)	128
Net increase (decrease) in cash and cash equivalents	195	(29)
Cash and cash equivalents at beginning of year	168	190
Cash and cash equivalents at end of period	$ 363	$ 161

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. General

The consolidated financial statements included in this report are unaudited and, in the opinion of management, include all adjustments necessary for a fair presentation of financial position and results of operations. All adjustments are of a normal recurring nature. Such financial statements are presented in accordance with the Securities and Exchange Commission's ("SEC") disclosure requirements for Form 10-Q.

These interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the related notes filed with the SEC in Unocal Corporation's 2002 Annual Report on Form 10-K.

For the purpose of this report, Unocal Corporation ("Unocal") and its consolidated subsidiaries, including Union Oil Company of California ("Union Oil"), are referred to as the "Company."

The consolidated financial statements of the Company include the accounts of subsidiaries in which a controlling interest is held. Investments in entities without a controlling interest are accounted for by the equity method or cost basis. Under the equity method, the investments are stated at cost plus the Company's equity in undistributed earnings and losses after acquisition. Income taxes estimated to be payable when earnings are distributed are included in deferred income taxes.

Results for the six months ended June 30, 2003, are not necessarily indicative of future financial results.

Certain items in the financial statements of the prior periods have been reclassified to conform to the 2003 presentation.

2. Accounting Changes

SFAS No. 143: Effective January 1, 2003, the Company adopted Statement of

Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." If a reasonable estimate of fair value can be made, this Statement requires that the Company recognize liabilities related to the legal obligations associated with the retirement of its tangible long-lived assets in the periods in which the obligations are incurred (typically when the assets are installed). These obligations include the required decommissioning and removal of certain oil and gas platforms, plugging and abandonment of oil and gas wells and facilities and the closure and site restoration of certain mining facilities. The recognized liability amounts are based upon future retirement cost estimates and incorporate many assumptions such as expected economic recoveries of crude oil and natural gas, time to abandonment, future inflation rates and the risk free rate of interest adjusted for the Company's credit costs.

The Company has interests in some long-lived assets, such as commercial natural gas storage facilities, commercial crude oil and products storage facilities, commercial pipelines, etc. where the operations are not tied to any particular operating field reserves. As the Company expects these assets to continue operations for the foreseeable future, it cannot reasonably estimate when, or if, these facilities will be abandoned. Accordingly, the Company has not accrued abandonment and restoration liabilities for these assets. The Company will continue to monitor these assets for any changes to this position.

Prior to January 1, 2003, the Company was required under SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," to accrue its abandonment and restoration costs ratably over the productive lives of its assets using the units-of-production method. SFAS No. 19 resulted in higher costs being accrued early in the fields' lives when production was at its highest levels and abandonment and restoration costs accruals were matched with the revenues as oil and gas were produced.

Under SFAS No. 143, when the liabilities for asset retirement obligations are initially recorded at their fair value, capital costs of the related assets will be increased by equal corresponding amounts. Over time, changes in the present value of the liabilities will be accreted and expensed and the capitalized asset costs will be depreciated over the useful lives of the corresponding assets. Because SFAS No. 143 requires the use of interest accretion for revaluing asset retirement obligation liabilities as a result of the passage of time, associated accretion costs will be higher near the end of the fields' lives when oil and gas production and related revenues are at their lowest levels.

Accounting Principles Board ("APB") Opinion No. 20, "Accounting Changes" requires that the Company calculate the retroactive impact of adopting SFAS No. 143 from the inception of its asset retirement obligations to its January 1, 2003 adoption date. APB Opinion No. 20 requires that this impact be quantified and reported as a cumulative effect of an accounting change on the earnings statement. This cumulative effect includes the catch up of SFAS No. 143 accretion expense related to the fair value of the liabilities as well as the catch up of associated depreciation expense related to the increased capital costs of the corresponding assets. The cumulative effect also includes the reversal of abandonment and restoration costs previously charged to earnings under SFAS No. 19. In addition to the impact on earnings due to the differences in applying SFAS No. 19 and SFAS No. 143 to the Company's oil and gas operations, the cumulative effect also includes the impact related to the Company's mining operations under SFAS No. 143.

In the first quarter of 2003, the Company recognized a one time after-tax charge of $83 million as the cumulative effect of an accounting change related to the adoption of SFAS No. 143. The Company also increased its accrued abandonment and restoration liabilities by $268 million and increased its net properties by $138 million on the consolidated balance sheet as a result of the adoption of SFAS 143 as of January 1, 2003. The Company estimates that the impact of adopting SFAS No. 143 on its 2003 operating earnings will be an incremental charge of approximately $9 million after tax.

Listed below is SFAS No. 143 pro-forma liability and earnings information for the periods ended December 31, 2000, 2001 and 2002 and June 30, 2002:

Pro Forma SFAS 143 liability carrying amounts for the periods shown

(Millions of dollars)	2000	2001	2002
Carrying amount of liability at beginning of year	$629	$661	$713
Carrying amount of liability at end of period	$661	$713	$758

Pro Forma amounts assuming SFAS 143 was applied retroactively Millions of dollars (except per share amounts)	For the years ended December 31, 2000	2001	2002	For the Six Months Ended June 30, 2002
Net income as reported	$760	$615	$331	$136
Earnings per share as reported:				
Basic	$3.13	$2.52	$1.34	$0.55
Diluted	$3.08	$2.50	$1.34	$0.55
Pro forma net income	$740	$596	$312	$126
Pro forma earnings per share:				
Basic	$3.05	$2.44	$1.26	$0.52
Diluted	$3.00	$2.42	$1.26	$0.52

SFAS No. 146: Effective January 1, 2003, the Company adopted SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This Statement provides guidance on the recognition and measurement of liabilities associated with disposal activities. The adoption of the Statement did not have a material effect on the Company's financial position or results of operations.

SFAS No. 148: Effective January 1, 2003, the Company adopted SFAS No. 148, "Accounting for Stock-Based Compensation--Transition and Disclosure--an amendment of FASB Statement No. 123." The Statement provides for three methods of transitioning from the intrinsic value to the fair value method of accounting for stock-based compensation. This Statement also amended the disclosure requirements of SFAS No. 123 and APB Opinion No. 28, "Interim Financial Reporting," to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The disclosure requirements of the Statement were adopted in the Company's 2002 Annual Report on Form 10-K. The Company adopted the fair value recognition provisions of SFAS No. 148, on a prospective basis, effective January 1, 2003 (see note 7 for further details). This change is estimated to decrease 2003 after-tax income by approximately $5 million. When fully phased in for future grants over the next three years, the annual after-tax expense is estimated to be approximately $10 million. Adoption of the fair value recognition provisions will not have a material effect on the Company's 2003 financial position or results of operations.

SFAS No. 149: In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." This Statement amends and clarifies accounting for derivative instruments including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. The Company does not expect the adoption of SFAS No. 149 to have a significant impact on its financial position or results of operations.

SFAS No. 150: Effective April 1, 2003, the Company adopted SFAS No. 150, "Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity," which establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS No. 150 requires that the Company classify a financial instrument that is within its scope, which may have previously been reported as equity, as a liability or an asset in some circumstances. The adoption of the Statement did not have an effect on the Company's financial position.

FASB Interpretation No. 45: Effective January 1, 2003, the Company adopted FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." This Interpretation requires the recognition of certain guarantees as liabilities at fair market value and is effective for guarantees issued or modified after December 31, 2002. The Company has included the disclosure requirements of the Interpretation in note 14. The adoption of this Interpretation did not have a material effect on the Company's financial position or results of operations.

FASB Interpretation No. 46: Effective January 1, 2003, the Company adopted FASB Interpretation No. 46, "Consolidation of Variable Interest Entities." This Interpretation requires the consolidation of certain companies defined as variable interest entities. This Interpretation is effective for new variable interest entities as of February 1, 2003. The effective date for the consolidation of entities existing prior to February 1, 2003 is July 1, 2003. The Company has included the disclosure requirements of the Interpretation in this report and expects the adoption of the recognition (i.e., consolidation) requirements of the Interpretation to increase its consolidated long-term debt by approximately $78 million in the third quarter of 2003. This amount reflects third-party debt related to Dayabumi Salak Pratama, Ltd. ("DSPL"), an equity investee that sells electricity generated from geothermal steam in Indonesia (see note 12 for further details). An additional $242 million, currently classified as minority interests, related to a partnership interest in Spirit Energy 76 Development, L.P. ("Spirit LP"), would have been required to be consolidated as long-term debt under this Interpretation had it not been paid in July 2003 (see notes 12 and 18 for further detail).

Consistent with SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," costs of acquiring oil and gas drilling rights have been classified as tangible assets in property, plant and equipment. The Company understands the staff of the SEC believes SFAS No. 19 does not provide guidance as to whether these assets should be classified as tangible or intangible and therefore believe SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," would require that drilling rights be classified as an intangible asset. The SEC has requested the FASB to address this perceived conflict within the related FASB statements. The resolution of this issue will have no impact on the Company's results of operations. If the

FASB concurs with the SEC, it would result in additional disclosures and a balance sheet reclassification of these assets from Properties-net to Intangible Assets.

3. Other Financial Information

During the second quarters of 2003 and 2002, approximately 25 percent and 23 percent, respectively, of total sales and operating revenues were attributable to the resale of liquids and natural gas purchased from others in connection with marketing activities. For the six months ended June 30, 2003 and 2002, these percentages were approximately 25 percent and 22 percent, respectively. Related purchase costs are classified as expense in the crude oil, natural gas and product purchase category on the consolidated earnings statement.

Capitalized interest totaled $19 million and $10 million for the second quarters of 2003 and 2002, respectively. For the six months ended June 30, 2003 and 2002, capitalized interest totaled $35 million and $19 million, respectively. The increase was primarily due to the capitalized interest related to the West Seno oil and gas development project in the deepwater Kutei Basin, offshore East Kalimantan, Indonesia, and the Azerbaijan International Operating Company ("AIOC") development of Phase I of the offshore Azeri field in the Azeri-Chirag-Gunashli structure in the Azerbaijan sector of the Caspian Sea.

Exploration expense on the consolidated earnings statement consisted of the following:

	For the Three Months Ended June 30		For the Six Months Ended June 30	
Millions of dollars	2003	2002	2003	2002
Exploration operations	$ 16	$ 25	$ 31	$ 48
Geological and geophysical	20	8	34	19
Amortization of exploratory leasehold costs	47	23	71	45
Leasehold rentals	5	5	7	8
Exploration expense	$ 88	$ 61	$ 143	$ 120

Amortization of exploratory leasehold costs included a $26 million pre-tax provision that was a result of the Company's intention to relinquish about 45 deepwater Gulf of Mexico blocks before their expiration dates. The Company intends to focus its deepwater Gulf of Mexico land position on those Outer Continental Shelf blocks that have the best potential.

4. Restructuring

In June 2003, the Company adopted a restructuring plan that resulted in the accrual of a $27 million pre-tax restructuring charge. The charge included the estimated costs of terminating 219 employees. The plan involves the streamlining of the organizational structures in order to align them with the Company's portfolio requirements and business needs. Approximately 37 of the affected employees are from various exploration and production business units and 182 are from other organizations, including corporate staff. The restructuring charge included approximately $21 million for termination costs to be paid to the employees over time, approximately $2 million for outplacement and other costs and $4 million for pension and post retirement expenses. The restructuring charge is included in selling, administrative and general expense on the consolidated earnings statement. At June 30, 2003, 51 employees had been terminated or had received termination notices as a result of the plan, with additional notifications to be made in the third quarter. The majority of these restructuring costs will be paid in 2004.

In 2002, the Company's Gulf Region business unit, which is part of the U.S. Lower 48 operations in the Exploration and Production segment, adopted a restructuring plan that resulted in the accrual of a $19 million pre-tax restructuring charge. The charge included the estimated costs of terminating 202 employees, all of whom were terminated in 2002. At June 30, 2003, approximately $17 million of the restructuring costs had been paid and charged against the liability, leaving accrued costs of $2 million on the consolidated balance sheet at June 30, 2003. The remaining costs are expected to be paid by the end of 2003.

Also in 2002, the Company adopted a restructuring plan that resulted in the accrual of a $4 million pre-tax restructuring charge related to Exploration and Production operations in Alaska. The restructuring charge reflected the costs of terminating 46 employees, of whom 43 had been terminated as of June 30, 2003. Approximately $2 million of the restructuring costs had been paid and charged against the liability, leaving accrued costs of $2 million on the consolidated balance sheet at June 30, 2003. The remaining costs are expected to be paid during 2003 and the first half of 2004.

5. Income Taxes

Income taxes on earnings from continuing operations for the second quarter and six months periods of 2003 were $133 million and $301 million, respectively, compared with $95 million and $135 million for the comparable periods of 2002. The effective income tax rate for both the second quarter and six months periods of 2003 was 44 percent, compared with 45 percent and 49 percent for the comparable periods of 2002. The lower effective tax rate in 2003, as compared with 2002, reflects the mix of positive domestic and foreign earnings in 2003 compared to the mix of domestic losses and foreign earnings in 2002. Foreign earnings are generally taxed at higher rates.

6. Earnings Per Share

The following are reconciliations of the numerators and denominators of the basic and diluted earnings per share ("EPS") computations for earnings from continuing operations for the second quarters and six months ended June 30, 2003 and 2002:

Millions except per share amounts	Earnings (Numerator)	Shares (Denominator)	Per Share Amount
Three months ended June 30, 2003			
Earnings from continuing operations	$ 169	258.2	
Basic EPS			$ 0.66
Effect of dilutive securities			
Options and common stock equivalents		1.6	
	169	259.8	$ 0.65

Distributions on subsidiary trust preferred securities (after-tax)	7	12.3	
Diluted EPS	$ 176	272.1	$ 0.65
Three months ended June 30, 2002			
Earnings from continuing operations	$ 113	244.6	
Basic EPS			$ 0.46
Effect of dilutive securities			
Options and common stock equivalents		1.2	
Diluted EPS	113	245.8	$ 0.46
Distributions on subsidiary trust preferred securities (after-tax)	7	12.3	
Antidilutive	$ 120	258.1	$ 0.46

Not included in the computation of diluted EPS for the three months ended June 30, 2003 and 2002, were options outstanding to purchase approximately 8.9 million and 1.9 million shares, respectively, of common stock. These options were not included in the computation as the exercise prices were greater than average market prices of the common shares during the respective quarters.

Millions except per share amounts	Earnings (Numerator)	Shares (Denominator)	Per Share Amount
Six months ended June 30, 2003			
Earnings from continuing operations	$ 386	258.1	
Basic EPS			$ 1.50
Effect of dilutive securities			
Options and common stock equivalents		1.5	
	386	259.6	$ 1.49
Distributions on subsidiary trust preferred securities (after-tax)	14	12.3	
Diluted EPS	$ 400	271.9	$ 1.47
Six months ended June 30, 2002			
Earnings from continuing operations	$ 135	244.4	
Basic EPS			$ 0.55
Effect of dilutive securities			
Options and common stock equivalents		1.1	
Diluted EPS	135	245.5	$ 0.55
Distributions on subsidiary trust preferred securities (after-tax)	14	12.3	

Antidilutive	$ 149	257.8	$ 0.58

Not included in the computation of diluted EPS for the six months ended June 30, 2003 and 2002, were options outstanding to purchase approximately 10.5 million and 3.3 million shares, respectively, of common stock. These options were not included in the computation as the exercise prices were greater than average market prices of the common shares during the respective periods.

Basic and diluted earnings per common share for discontinued operations were as follows:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Millions except per share amounts	2003	2002	2003	2002
Basic earnings per share of common stock:				
Discontinued operations:				
Earnings from discontinued operations	$ 8	$ 1	$ 8	$ 1
Weighted average common shares outstanding	258.2	244.6	258.1	244.4
Earnings from discontinued operations	$ 0.03	$ -	$ 0.03	$ -
Dilutive earnings per share of common stock:				
Discontinued operations:				
Earnings from discontinued operations	$ 8	$ 1	$ 8	$ 1
Weighted average common shares outstanding	272.1	245.9	271.9	245.5
Earnings from discontinued operations	$ 0.03	$ -	$ 0.03	$ -

7. Stock-Based Compensation

Prior to 2003, the Company applied APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for stock-based compensation. Before 2003, stock-based compensation expense recognized in the Company's consolidated earnings included expenses related to the Company's various cash incentive plans that are paid to certain employees based upon defined measures of the Company's common stock price performance and total shareholder return. In addition, the amounts also included expenses related to the Company's Pure Resources, Inc. ("Pure") subsidiary, which had its own stock-based compensation plans. Under Opinion No. 25, stock-based employee compensation cost was not recognized in earnings when stock options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective January 1, 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," prospectively to all employee awards granted, modified, or settled after December 31, 2002. Therefore, the cost related to stock-based employee compensation included in the determination of net earnings for 2003 is less than that which would have been recognized if the fair value based method had been applied to all awards since the original effective date of SFAS No. 123. The following table illustrates the effect on net earnings and earnings per share if the fair value based method had been applied to all outstanding and unvested awards in each period:

Millions of dollars except per share amounts	For the Three Months Ended June 30, 2003	2002	For the Six Months Ended June 30, 2003	2002
Net earnings				
As reported	$ 177	$ 114	$ 311	$136
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects and minority interests	4	1	6	8
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects and minority interests	(6)	(7)	(10)	(19)
Pro forma net earnings	$ 175	$ 108	$ 307	$ 125
Net earnings per share:				
Basic - as reported	$ 0.69	$ 0.46	$ 1.21	$ 0.55
Basic - pro forma	$ 0.68	$ 0.44	$ 1.19	$ 0.51
Diluted - as reported	$ 0.68	$ 0.46	$ 1.20	$ 0.55
Diluted - pro forma	$ 0.67	$ 0.44	$ 1.18	$ 0.51

8. Comprehensive Income

The Company's comprehensive income was:

Millions of dollars	For the Three Months Ended June 30, 2003	2002	For the Six Months Ended June 30, 2003	2002
Net earnings	$ 177	$ 114	$ 311	$ 136
Change in unrealized loss on hedging instruments (a)	7	(1)	(3)	(9)
Reclassification adjustment for settled hedging contracts (b)	4	4	11	(1)
Unrealized foreign currency translation adjustments	68	35	114	32
Total comprehensive income	$ 256	$ 152	$ 433	$ 158

9. Cash and Cash Equivalents

Millions of dollars	At June 30, 2003	At December 31, 2002
Cash	$ 119	$ 58
Time deposits	112	110
Restricted cash	1	-
Marketable securities	131	-
Cash and cash equivalents	$ 363	$ 168

The marketable securities at June 30, 2003 reflect the Company's short-term investment in a money market fund which invests in U.S. Treasury and other U.S. government agency obligations plus high quality bonds and commercial paper obligations of domestic corporations. The fund is rated "AAA" by Moody's Investors Service, Inc. and Standard & Poor's Ratings Services.

10. Assets Held for Sale

The Company announced that it has initiated a divestiture program that will involve approximately 100 fields in the Gulf of Mexico shelf and onshore, including associated pipelines. The Company is currently in the process of marketing the properties for sale to several potential buyers.

The Company's Unocal North Sumatra Geothermal, Ltd. subsidiary has agreed to sell its rights and interest in the Sarulla geothermal project on the island of Sumatra, Indonesia to the Indonesian state electricity company. The anticipated sales price is $60 million. The transaction is expected to close in the third quarter of 2003, and the Company expects to record a gain on the transaction.

Details of the assets and liabilities for the assets classified as held for sale, as of June 30, 2003, are presented below:

Millions of dollars	U.S. Lower 48	Midstream	Geothermal	Total
Assets				
Properties - net (b)	$ 391	$ 7	$ 26	$ 424
Other assets	8	-	-	8
Total assets	$ 399	$ 7	$ 26	$ 432
Liabilities				
Accrued abandonment, restoration and environmental liabilities	$ 94	$ -	$ -	94
Other deferred credits and liabilities	6	-	-	6
Total liabilities	$ 100	$ -	$ -	$ 100

11. Long Term Debt and Credit Agreements

During the first six months of 2003, the Company's consolidated debt, including the current portion, decreased by $32 million. The Company retired $89 million in 9.25% debentures and paid down $10 million of medium-term notes which matured. The Company also repurchased $15 million of the $200 million outstanding balance in 6.375% notes due in 2004 and repaid $20 million of 6.20% Industrial Development Revenue Bonds.

These decreases were partially offset by $79 million drawn under the Overseas Private Investment Corporation ("OPIC") Financing Agreement for the first phase of the West Seno project in Indonesia. The Company and its co-venturer completed financing arrangements for a portion of the total costs of the project through two loans arranged with OPIC. One loan is $300 million for the first phase, and the other loan is $50 million for the second phase. The second phase loan will be subject to further due diligence by the lender. This initial draw down has a floating rate that is adjusted weekly, which as of June 30, 2003, was set at 1.15%.

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At June 30, 2003, the 3-year $295 million Canadian dollar-denominated non-revolving credit facility was unchanged; however due to increasing strength of the Canadian dollar, borrowings under the credit facility translated to $218 million, using applicable foreign exchange rates, or a $32 million increase from year-end 2002.

12. Variable Interest Entities

DSPL is a variable interest entity formed for the purpose of building and operating a geothermal energy fueled power generating facility in Indonesia. Under a long-term electricity sales contract, DSPL provides power to the Indonesian state-owned electricity company, PT. PLN (Persero) ("PLN"). Unocal Geothermal of Indonesia, Ltd. ("UGI") owns a 50 percent interest in DSPL and is under contract to administer DSPL operations. DSPL has no employees of its own. DSPL had loans and notes payable totaling $82 million at June 30, 2003. Neither UGI nor the Company has guaranteed DSPL's debt obligations, which are non-recourse. Effective in the third quarter of 2003, FASB Interpretation No. 46 (see note 2 for further details), will require the Company to consolidate DSPL, resulting in the reporting of $78 million as long-term debt on the consolidated balance sheet at that time. At June 30, 2003, the Company's maximum exposure to loss as a result of its involvement with DSPL was approximately $95 million.

An additional $242 million, currently classified as minority interests, related to a partnership interest in Spirit LP, would have been required to be consolidated as long-term debt under FASB Interpretation No. 46 had it not been paid in July 2003 (see note 18 for further detail).

13. Accrued Abandonment, Restoration and Environmental Liabilities

Effective January 1, 2003, the Company adopted SFAS No. 143 which increased its accrued abandonment and restoration liabilities by $268 million (see note 2 for further detail). At January 1, 2003 and June 30, 2003, the Company had accrued $758 million and $771 million, respectively, in estimated abandonment and restoration costs as liabilities. The increase in the liability account from January 1, 2003 was due to accrued pre-tax accretion expense of $22 million. This accrual was partially offset by abandonment liability settlements of $9 million completed during the period. There were no material abandonment and restoration liabilities incurred or revisions in abandonment and restoration cost estimates during the first six months of 2003. The Company's total accrued abandonment and restoration liabilities of $771 million at June 30, 2003, include $94 million in abandonment liabilities associated with assets held for sale (see note 10 for further detail).

The Company's reserve for environmental remediation obligations at June 30, 2003 totaled $267 million, of which $121 million was included in current liabilities. This compared with $245 million at December 31, 2002, of which $113 million was included in current liabilities.

14. Commitments and Contingencies

The Company has contingent liabilities with respect to material existing or potential claims, lawsuits and other proceedings, including those involving environmental, tax, guarantees and other matters, certain of which are discussed more specifically below. The Company accrues liabilities when it is probable that future costs will be incurred and such costs can be reasonably estimated. Such accruals are based on developments to date, the Company's estimates of the outcomes of these matters and its experience in contesting, litigating and settling other matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which could have a material effect on the Company's future results of operations and financial condition or liquidity.

Environmental matters

The Company continues to move forward to address environmental issues for which it is responsible. The Company, in cooperation with regulatory agencies and others, follows procedures that it has established to identify and cleanup contamination associated with its past operations. The Company is subject to loss contingencies pursuant to federal, state, local and foreign environmental laws and regulations. These include existing and possible future obligations to investigate the effects of the release or disposal of certain petroleum, chemical and mineral substances at various sites; to remediate or restore these sites; to compensate others for damage to property and natural resources, for remediation and restoration costs and for personal injuries; and to pay civil penalties and, in some cases, criminal penalties and punitive damages. These obligations relate to sites owned by the Company or others and are associated with past and present operations, including sites at which the Company has been identified as a potentially responsible party ("PRP") under the federal Superfund laws and comparable state laws. Liabilities are accrued when it is probable that future costs will be incurred and such costs can be reasonably estimated. However, in many cases, investigations are not yet at a stage where the Company is able to determine whether it is liable or, even if liability is determined to be probable, to quantify the liability or estimate a range of possible exposure.
In such cases, the amounts of the Company's liabilities are indeterminate due to the potentially large number of claimants for any given site or exposure, the unknown magnitude of possible contamination, the imprecise and conflicting engineering evaluations and estimates of proper clean-up methods and costs, the unknown timing and extent of the corrective actions that may be required, the uncertainty attendant to the possible award of punitive damages, the recent judicial recognition of new causes of action, the present state of the law, which often imposes joint and several and retroactive liabilities on PRPs, the fact that the Company is usually just one of a number of companies identified as a PRP, or other reasons.

As disclosed in note 13, at June 30, 2003, the Company had accrued $267 million for estimated future environmental assessment and remediation costs at various sites where liabilities for such costs are probable and reasonably estimable. The Company may also incur additional liabilities in the future at sites where remediation liabilities are probable but future environmental costs are not presently reasonably estimable because the sites have not been assessed or the assessments have not advanced to the stage where costs are reasonably estimable.

At those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $205 million. The amount of such possible additional costs reflects the aggregate of the high ends of the ranges of costs of feasible alternatives identified by the Company for those sites with respect to which investigation or feasibility studies have advanced to the stage of analyzing such alternatives. However, such estimated possible additional costs are not an estimate of the total remediation costs beyond the amounts reserved, because there are sites where the Company is not yet in a position to estimate all, or in some cases any, possible additional costs. Both the amounts reserved and estimates of possible additional costs may change in the near term, and in some cases could change substantially, as additional information becomes available regarding the nature and extent of site contamination, required or agreed-upon remediation methods and other actions by government agencies and private parties.

The accrued costs and the possible additional costs are shown below for four categories of sites:

	At June 30, 2003	
Millions of dollars	Reserve	Possible Additional Costs
Superfund and similar sites	$ 17	$ 15
Active Company facilities	31	25
Company facilities sold with retained liabilities and former Company-operated sites	98	80
Inactive or closed Company facilities	121	85
Total	$ 267	$ 205

The time frames over which the amounts included in the reserve may be paid extend from the near term to several years into the future. The sites included in the above categories are in various stages of investigation and remediation; therefore, the related payments against the existing reserve will be made in future periods. Also, some of the work is dependent upon reaching agreements with regulatory agencies and/or other third parties on the scope of remediation work to be performed, who will perform the work, the timing of the work, who will pay for the work and other factors that may have an impact on the timing of the payments for amounts included in the reserve. For some sites, the remediation work will be performed by other parties, such as the current owners of the sites, and the Company has a contractual agreement to pay a share of the remediation costs. For these sites, the Company generally has less control over the timing of the work and consequently the timing of the associated payments. Based on available information, the Company estimates that the majority of the amounts included in the reserve will be paid within the next three to five years.

At the sites where the Company has contractual agreements to share remediation costs with third parties, the reserve reflects the Company's estimated shares of those costs. In many of the oil and gas sites, remediation cost sharing is included in joint venture agreements that were made with third parties during the original operation of the sites. In many cases where the Company sold facilities or a business to a third party, sharing of remediation costs for those sites may be included in the sales agreement.

Contamination at the sites of the "Superfund and similar sites" category was the result of the disposal of substances at these sites by one or more PRPs. Contamination of these sites could be from many sources, of which the Company may be one. The Company has been notified that it is a PRP at the sites included in this category. At the sites where the Company has not denied liability, the Company's contribution to the contamination at these sites was primarily from operations identified below.

The "Active Company facilities" category includes oil and gas fields and mining operations. The oil and gas sites are primarily contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Contamination at the active mining sites was principally the result of the impact of mined material on the groundwater and/or surface water at these sites.

The "Company facilities sold with retained liabilities and former Company-operated sites" and "Inactive or closed Company facilities" categories include former Company refineries, transportation and distribution facilities and service stations. The required remediation of these sites is mainly for petroleum hydrocarbon contamination as the result of leaking tanks, pipelines or other equipment or impoundments that were used in these operations. Also, included in these categories are former oil and gas fields that the Company no longer operates. In most cases, these sites are contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Contamination at other sites in these categories of sites was the result of former industrial chemical and polymers manufacturing and distribution facilities, agricultural chemical retail businesses and ferromolybdenum production operations.

Superfund and similar sites - Included in this category of sites are:

o The McColl site in Fullerton, California
o The Operating Industries site in Monterey Park, California
o The Casmalia Waste site in Casmalia, California

At June 30, 2003, Unocal had received notifications from the U.S. Environmental Protection Agency ("EPA") that the Company may be a PRP at 23 sites and may share certain liabilities at these sites. Of the total, four sites are under investigation and/or litigation and the Company's potential liability is not presently determinable and at two sites the Company's potential liability appears to be de minimis. Of the remaining 17 sites, where the Company has concluded that liability is probable and to the extent costs can be reasonably estimated, a reserve of $13 million has been established for future remediation and settlement costs.

Various state agencies and private parties had identified 21 other similar PRP sites. Four sites are under investigation and/or litigation and the Company's potential liability is not presently determinable and for two sites, the Company has denied responsibility. At two sites the Company's potential liability appears to be de minimis. Where the Company has concluded that liability is probable and to the extent costs can be reasonably estimated at the remaining 13 sites, a reserve of $4 million has been established for future remediation and settlement costs.

The sites discussed above exclude 121 sites where the Company's liability has been settled, or where the Company has no evidence of liability and there has been no further indication of liability by government agencies or third parties for at least a 12-month period.

The Company does not consider the number of sites for which it has been named a PRP as a relevant measure of liability. Although the liability of a PRP is generally joint and several, the Company is usually just one of numerous companies designated as a PRP. The Company's ultimate share of the remediation costs at those sites often is not determinable due to many unknown factors. The solvency of other responsible parties and disputes regarding responsibilities may also impact the Company's ultimate costs.

Active Company facilities - Included in this category are:

o The Molycorp molybdenum mine in Questa, New Mexico
o The Molycorp lanthanide facility in Mountain Pass, California
o Alaska oil and gas properties

The Company has a reserve of $31 million for estimated future costs of remedial orders, corrective actions and other investigation, remediation and monitoring obligations at certain operating facilities and producing oil and gas fields. The Company made payments of $7 million for this category of sites in the first six months of 2003.

Company facilities sold with retained liabilities and former Company-operated sites - Company facilities sold with retained liabilities include:

o West Coast refining, marketing and transportation sites
o Auto/truckstop facilities in various locations in the U.S.
o Industrial chemical and polymer sites in the South, Midwest and California
o Agricultural chemical sites in the West and Midwest.

In each sale, the Company retained a contractual remediation or indemnification obligation and is responsible only for certain environmental problems that resulted from operations prior to the sale. The reserve represents estimated future costs for remediation work: identified prior to the sale of these sites; included in negotiated agreements with the buyers of these sites where the Company retained certain levels of remediation liabilities; and/or identified in subsequent claims made by buyers of the properties. Former Company-operated sites include service stations, distribution facilities and oil and gas fields that were previously operated but not owned by the Company.

The Company has an aggregate reserve of $98 million for this group of sites. During the first six months of 2003, provisions of $9 million for the "Company facilities sold with retained liabilities and former Company-operated sites" category were recorded. These provisions included the estimated cleanup costs for oil fields located in Michigan and California that were formerly operated by the Company. The estimated costs are based on assessments recently performed at the sites. The provisions for this category of sites were also the result of revised remediation cost estimates that were identified during the first and second quarters of 2003 for former service station sites.

Payments of $15 million were made during the first six months of 2003 for sites in this category.

Inactive or closed Company facilities - The major sites in this category are:

o The Guadalupe oil field on the central California coast
o The Molycorp Washington and York facilities in Pennsylvania
o The Beaumont Refinery in Texas.

A reserve of $121 million has been established for these types of facilities. During the first six months of 2003, the Company recorded provisions of $40 million related to sites in this category primarily for the Guadalupe oil field and for remediation projects at the Beaumont Refinery. For the Guadalupe oil field site, it was determined that contaminated soil excavated from the site will probably be taken to an offsite landfill for disposal. The soil is contaminated with diluent, a kerosene-like additive used in the field's former operations. Previously, the Company had planned to remediate the soil on-site; however, a preliminary draft report for the ecological risk study being conducted indicates that on-site remediation is not viable. The provisions recorded for the site include the costs for the offsite disposal alternative. The provisions recorded for the Guadalupe oil field also include estimated costs for remediation work that is ongoing at the site. This work includes groundwater monitoring, operation and maintenance of remedial systems, restoration, site assessment and regulatory agency oversight and permitting procedures. The provisions for these costs are based on data from various studies and assessments that have been completed for the site in conjunction with data provided by the project management system the Company has in place.

A provision was also recorded for the Company's former Beaumont, Texas refinery. The Company has been working with the Texas Commission on Environmental Quality ("TCEQ") to develop plans for closing impoundments used in the site's former operations and for other remediation projects. In the first six months of 2003, the Company recorded a provision for the revised estimated costs of the impoundment closure plan based on the TCEQ initial draft permit that was issued for the site.

Payments of $7 million were made during the first six months of 2003 for sites in this category.

The Company is subject to federal, state and local environmental laws and regulations, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), as amended, the Resource Conservation and Recovery Act ("RCRA") and laws governing low level radioactive materials. Under these laws, the Company is subject to existing and/or possible obligations to remove or mitigate the environmental effects of the disposal or release of certain chemical, petroleum and radioactive substances at various sites. Corrective investigations and actions pursuant to RCRA and other federal, state and local environmental laws are being performed at the Company's facility in Beaumont, Texas, a former agricultural chemical facility in Corcoran, California, and Molycorp's facility in Washington, Pennsylvania. In addition, Molycorp is required to decommission its Washington and York facilities in Pennsylvania pursuant to the terms of their respective radioactive source materials licenses and decommissioning plans.

The Company also must provide financial assurance for future closure and post-closure costs of its RCRA-permitted facilities and for decommissioning costs at facilities that are under radioactive source materials licenses. Pursuant to a 1998 settlement agreement between the Company and the State of California (and the subsequent stipulated judgment entered by the Superior Court), the Company must provide financial assurance for anticipated costs of remediation activities at its inactive Guadalupe oil field. Also, pursuant to a 1995 settlement agreement between Molycorp and the California Department of Toxic Substances Control (and subsequent final judgment entered by the Superior Court), the Company must provide financial assurance for anticipated costs of disposing of certain wastes, as well as closing facilities associated with the handling of those wastes, at Molycorp's Mountain Pass, California, facility. At June 30, 2003, amounts in the remediation reserve for these facilities totaled

$124 million, as included in the previously discussed "Active Company Facilities" and "Inactive or closed Company facilities" categories. At those sites where investigations or feasibility studies have advanced to the stage of analyzing alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $55 million. Although any possible additional costs for these sites are likely to be incurred at different times and over a period of many years, the Company believes that these obligations could have a material adverse effect on the Company's results of operations but are not expected to be material to the Company's consolidated financial condition or liquidity.

The total environmental remediation reserve recorded on the consolidated balance sheet represents the Company's estimates of assessment and remediation costs based on currently available facts, existing technology and presently enacted laws and regulations. The remediation cost estimates, in many cases, are based on plans recommended to the regulatory agencies for approval and are subject to future revisions. The ultimate costs to be incurred could exceed the total amounts reserved. The reserve will be adjusted as additional information becomes available regarding the nature and extent of site contamination, required or agreed-upon remediation methods and other actions by government agencies and private parties. Therefore, amounts reserved may change substantially in the near term.

The Company maintains insurance coverage intended to reimburse the cost of damages and remediation related to environmental contamination resulting from sudden and accidental incidents under current operations. The purchased coverages contain specified and varying levels of deductibles and payment limits. Although certain of the Company's contingent legal exposures enumerated above are uninsurable either due to insurance policy limitations, public policy or market conditions, management believes that its current insurance program significantly reduces the possibility of an incident causing a material adverse financial impact to the Company.

Certain Litigation and Claims

City of Santa Monica MTBE Lawsuit: In 2000, the City of Santa Monica, California (the "City") sued Shell Oil Company and other oil companies, including the Company, for contamination with methyl tertiary butyl ether ("MTBE") and a related chemical, tertiary butyl alcohol ("TBA"), of water pumped from the City's Charnock wellfield (City of Santa Monica v. Shell Oil Company et al. California Superior Court, Orange County, Case No. 01CC04331). The City alleges that releases from sites owned by Shell, ChevronTexaco Corporation and ExxonMobil Corporation caused the wellfield to be shut down, that releases from sites owned by Unocal subsequently impacted the wellfield. The City also alleges Unocal is liable under a products liability theory for gasoline it manufactured or sold that was ultimately distributed to area facilities operated by others. The Company is also subject to potential contractual liability for contamination from former facilities related to our gasoline marketing business sold in 1997. In 2001, Shell filed a cross-complaint against the Company and other oil companies, seeking the recovery of the funds it has expended to respond to the contamination.

Several of the defendants other than the Company have entered into settlement agreements with the City, which are subject to court approval. The Company's current analysis does not indicate any such liabilities are likely to be significant.

Based on a rigorous technical analysis of the data, the Company believes it has strong defenses to the allegations in the complaint applicable to both its former operations and facilities and the product liability claims, including the lack of evidence that its former service stations or activities are responsible for any contamination that has reached or threatens the wellfield. The Company intends to request completion of limited discovery previously stayed that may support filing of appropriate motions for summary adjudication on the City's most significant claims.

For several years prior to the City's suit, the EPA and the California Regional Water Quality Control Board have asserted jurisdiction over contamination of groundwater potentially affecting the wellfield, and these agencies have issued a number of orders under RCRA and state law to the Shell defendants and the other defendant oil companies, including the Company, with respect to both investigation of individual facilities and regional contamination, and requiring replacement of water lost to the City, which Shell is currently providing. In January 2003, the EPA Regional Administrator for Region IX wrote to the settling parties advising that it intended to issue a unilateral order to all parties whose releases have been demonstrated to contribute to contamination in the Charnock Sub-Basin ordering cleanup of MTBE and TBA "hot spots," unless a settlement in principle among all concerned parties was reached by June 30, 2003. The Company has submitted to these agencies several technical analyses, which it believes demonstrate that its sites are not a part of any regional contamination problem, but, rather, present, at the most, localized issues which the Company, under agency oversight, has been successfully resolving. The Company met with senior EPA and Water Board Officials in May 2003 to discuss these issues, and the EPA has so far taken no action on its January 2003 letter.

Agrium Litigation: In June 2002, a lawsuit was filed against the Company by Agrium Inc., a Canadian corporation, and Agrium U.S. Inc., its U. S. subsidiary, in the Superior Court of the State of California for the County of Los Angeles (Agrium U.S. Inc. and Agrium Inc. v. Union Oil Company of California, Case No. BC275407) (the "Agrium Claim"). Simultaneously, the Company filed suit against the Agrium entities ("Agrium") in the U.S. District Court for the Central District of California (Union Oil Company of California v. Agrium, Inc., Case No. 02-04518 NM) (the "Company Claim"). The Company subsequently removed the Agrium Claim to the U.S. District Court for the Central District of California (Case No. 02-04769 NM). The federal court has since remanded the Agrium Claim to the California Superior Court. In addition, the Company has initiated arbitration concerning the Gas Purchase and Sale Agreement ("GPSA") between the Company and Agrium U.S. Inc. (AAA Case No. 70 198 00539 02) (the "Arbitration").

The Agrium Claim alleges numerous causes of action relating to Agrium's purchase from the Company of a nitrogen-based fertilizer plant on the Kenai Peninsula, Alaska, in September 2000. The primary allegations involve the Company's obligation to supply natural gas to the plant pursuant to the GPSA. Agrium alleges that the Company misrepresented the amount of natural gas reserves available for sale to the plant as of the closing of the transaction and that the Company has failed to develop additional natural gas reserves for sale to the plant. Agrium also alleges that the Company misrepresented the condition of the general effluent sewer at the plant and made misrepresentations regarding other environmental matters.

Agrium seeks damages in an unspecified amount for breach of such representations and warranties, as well as for alleged misconduct by the Company in operating and managing certain oil and gas leases and other facilities. Agrium also seeks declaratory relief concerning the base price of gas under the GPSA, as well as for the calculation of payments under a "Retained Earnout" covenant that entitles the Company to certain contingent payments based on the price of ammonia subsequent to the September 2000 closing. The complaint includes demands for punitive damages and attorneys' fees.

In September 2002, Agrium amended its complaint to add allegations that the Company breached certain conditions of the September 2000 closing, breached certain indemnification obligations, and violated the pertinent health and safety code. Agrium also asked for recission of the sale of the fertilizer plant, in addition, or as an alternative, to money damages.

In the Company Claim, the Company seeks declaratory relief in its favor against the allegations of Agrium set forth above and for judgment on the Retained Earnout in the amount of $17 million plus interest accrued subsequent to May 2002.

The GPSA contains a contractual limit on liquidated damages of $25 million per year, not to exceed a total of $50 million over the life of the agreement. In addition, the agreement for the sale of the plant (the "PSA") contains a limit on damages of $50 million. The Company believes it has a meritorious defense to each of the Agrium claims, but that in any event its exposure to damages for all disputes is limited by the agreements. Agrium alleges that it is entitled to recover damages in excess of those amounts.

The Company believes that certain portions of its disputes with Agrium are subject to binding arbitration under the terms of the GPSA. The Company initiated the Arbitration to determine the amount and delivery rate of the remaining gas supply available under that agreement. Agrium claims the dispute resolution provisions of the PSA supersede the arbitration provisions of the GPSA. On July 16, 2003, the court approved an agreed stipulation between the parties to submit all issues under the GPSA to arbitration. Discovery is now proceeding.

Bangladesh Moulavi Bazar #1 Claims: In July 2002, the Company's subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. ("Unocal Blocks 13 and 14 Ltd.") received a letter from the Bangladesh Oil, Gas & Mineral Corporation ("Petrobangla") claiming, on behalf of the Bangladesh government and Petrobangla, compensation allegedly due in the amount of $685 million for 246 BCF of recoverable natural gas allegedly "lost and damaged" in a 1997 blowout and ensuing fire during the drilling by Occidental Petroleum Corporation (known at that time in Bangladesh as Occidental of Bangladesh Ltd.) ("OBL"), as operator, of the Moulavi Bazar #1 ("MB #1") exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. The Company and OBL believe that the claim vastly overstates the amount of recoverable gas involved in the blowout.

Consistent with worldwide industry contracting practice, there was no provision in the PSC for compensating the Bangladesh government or Petrobangla for resources lost during the contractors' operations. Even if some form of compensation were due, the Company and OBL believe that settlement compensation for the blowout was fully addressed in a 1998 Supplemental Agreement to the PSC (the "Supplemental Agreement"), which, among other matters, waived OBL's then 50-percent contractor's share (as well as the then 50-percent contractor's share held by the Company's Unocal Bangladesh, Ltd., subsidiary ("Unocal Bangladesh")) of entitlement to the recovery of costs incurred in the blowout, waived their right to invoke force majeure in connection with the blowout, and reduced by five percentage points their contractors' profit share (with a concomitant increase in Petrobangla's profit share) of future production from the sands encountered by the MB #1 well to a drill depth of 840 meters or, if the blowout sand reservoir were not deemed commercial, from other commercial fields in the Moulavi Bazar "ring-fenced" area of Block 14. Consequently, the Company and OBL consider the matter closed and Unocal Blocks 13 and 14 Ltd. has advised Petrobangla that no additional compensation is warranted.

By Writ Petition Affidavit dated March 24, 2003, a concerned citizen filed suit in the Bangladesh lower court (Alam v. Bangladesh, Petrobangla, Department of Environment, and Unocal Bangladesh, Ltd., Supreme Court of Bangladesh, High Court Division, Writ Petition No. 2461 of 2003) on the basis of the MB #1 blowout. The Company was notified of the suit on May 26, 2003 when it received the court's order to show cause why the Supplemental Agreement should not be declared illegal and cancelled on account of its having been executed without lawful authority, and why Unocal Bangladesh should not be directed to stop exploration until it compensates for the MB#1 blowout. No hearing is currently scheduled on the matter, and the Company believes the action is not well founded.

Nuevo Energy Claim: In March 2003, the Company received a letter from Nuevo Energy Company regarding a contingent payment for the year 2002 owed by Nuevo to the Company under the terms of the 1996 Asset Purchase Agreement pursuant to which Nuevo purchased substantially all of the Company's operating California oil and gas properties. Notwithstanding that Nuevo had notified the Company in January 2003 of its estimate of the payment for 2002, Nuevo now claims that the long-standing calculation methodology for this payment was incorrect, that no payment should be due for 2002, and that the payment made for 2001 should be refunded. The Company disputes Nuevo's new position. The current disputed cash exposure to the Company is $27 million.

On June 30, 2003, Nuevo filed suit against Unocal in the U.S. District Court for the Central District of California, Case No. 03-4664 (RCx). Nuevo seeks $10.8 million, the amount Nuevo alleges it paid Unocal in error. Nuevo also seeks a declaratory judgment regarding its right to take deductions in calculating the contingent payment in the future. Unocal has counterclaimed, seeking in excess of $16 million for amounts currently owed under the contingent payment agreement and for a declaratory judgment regarding the rights and relations of Unocal and Nuevo under that agreement.

In view of the inherent difficulty of predicting the outcome of legal matters, the Company cannot state with confidence what the eventual outcome of the four preceding matters will be. However, based on current knowledge, none of the preceding matters is presently expected to have a material adverse effect on the Company's consolidated financial condition or liquidity, but each of them could have a material adverse effect on the Company's results of operations for the accounting period or periods in which one or more of them might be resolved adversely.

Tax matters

The Company believes it has adequately provided in its accounts for tax items and issues not yet resolved. Several prior material tax issues are unresolved. Resolution of these tax issues impact not only the year in which the items arose, but also the Company's tax situation in other tax years. With respect to 1979-1984 taxable years, all issues raised for these years have now been settled, with the exception of the effect of the carryback of a 1993 net operating loss ("NOL") to tax year 1984 and resultant credit adjustments. The 1985-1990 taxable years are before the Appeals division of the Internal Revenue Service. All issues raised with respect to those years have now been settled, with the exception of the effect of the 1993 NOL carryback and resultant adjustments. The Joint Committee on Taxation of the U.S. Congress has reviewed the settled issues with respect to 1979-1990 taxable years and no additional issues have been raised. While all tax issues for the 1979-1990 taxable years have been agreed and reviewed by the Joint Committee, these taxable years will remain open due to the 1993 NOL carryback. The 1993 NOL results from certain specified liability losses, which occurred during 1993, and which resulted in a tax refund of $73 million. Consequently, these tax years will remain open until the specified liability loss, which gave rise to the 1993 NOL, is finally determined by the Internal Revenue Service and is either agreed to with the IRS or otherwise concluded in the Tax Court proceeding. In 1999, the United States Tax Court granted Unocal's motion to amend the pleadings in its Tax Court cases to place the 1993 NOL carryback in issue. The 1991-1994 taxable years are now before the Appeals division of the Internal Revenue Service. The 1995-1997 taxable years are under examination by the Internal Revenue Service.

Guarantees Related to Assets or Obligations of Third Parties

The Company has agreed to indemnify certain third parties for particular future remediation costs that may be incurred for properties held by these parties. The guarantees were established when the Company either leased property from or sold property to these third parties. The properties may or may not have been contaminated by various Company operations. Where it has been or will be determined that the Company is responsible for contamination, the guarantees require the Company to pay the costs to remediate the sites to specified cleanup levels or to levels that will be determined in the future.

The maximum potential amount of future payments that the Company could be required to make under these guarantees is indeterminate primarily due to the following: the indefinite term of the majority of these guarantees; the unknown extent of possible contamination; uncertainties related to the timing of the remediation work; possible changes in laws governing the remediation process; the unknown number of claims that may be made; changes in remediation technology; and the fact that most of these guarantees lack limitations on the maximum potential amount of future payments.

The Company has accrued probable and reasonably estimable assessment and remediation costs for the locations covered under these guarantees. These amounts are included in the "Company facilities sold with retained liabilities and former Company-operated sites" category of the Company's reserve for environmental remediation obligations. At June 30, 2003, the reserve for this category totaled $98 million. For those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $80 million. See the discussion elsewhere in this footnote for additional information regarding this category.

The Company has guaranteed the debt of certain joint ventures accounted for by the equity method. The majority of this debt matures evenly through the year 2014. The maximum potential amount of future payments the Company could be required to make is approximately $21 million.

In the ordinary course of business, the Company has agreed to indemnify cash deficiencies for certain domestic pipeline joint ventures, which the Company accounts for on the equity method. These guarantees are considered in the Company's analysis of overall risk. Since most of these agreements do not contain spending caps, it is not possible to quantify the amount of maximum payments that may be required. Nevertheless, the Company believes the payments would not have a material adverse impact on its financial condition or liquidity.

Financial Assurance for Unocal Obligations

In the normal course of business, the Company has performance obligations which are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily cover self-insurance, site restoration, dismantlement and other programs where governmental organizations require such support. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed by the Company if drawn upon. At June 30, 2003, the Company had obtained various surety bonds for approximately $217 million. These surety bonds included a bond for $86 million securing the Company's performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of gas over a ten-year period that began in January of 1999 and will end in December of 2008 and approximately $131 million in various other routine performance bonds held by local, city, state and federal agencies. The Company also had obtained approximately $38 million in standby letters of credit at June 30, 2003. The Company has entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit.

The Company has various other guarantees for approximately $553 million. Approximately $134 million of the $553 million in guarantees represent financial assurance given by the Company on behalf of its Molycorp subsidiary relating to permits covering operations and discharges from its Questa, New Mexico, molybdenum mine. The Company's financial assurance is for the completion of temporary closure plans (required only upon cessation of operations) and other obligations required under the terms of the permits. The costs associated with the financial assurance are based on estimations provided by agencies of the state of New Mexico.

Guarantees for approximately $333 million of the $553 million would require the Company to obtain a surety bond or a letter of credit or establish a trust fund if its credit rating were to drop below investment grade--that is BBB- or Baa3 from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively.

Approximately $170 million of the surety bonds, letters of credit and other guarantees that the Company is required to obtain or issue reflect obligations that are already included on the consolidated balance sheet in other current liabilities and other deferred credits. The surety bonds, letters of credit and other guarantees may also reflect some of the possible additional remediation liabilities discussed earlier in this note.

Other matters

The Company has a lease agreement relating to its Discoverer Spirit deepwater drillship, with a remaining term of approximately 27 months at June 30, 2003. The drillship has a current minimum daily rate of approximately $224,000. The future remaining minimum lease payment obligation was approximately $182 million at June 30, 2003.

The Company also has other contingent liabilities with respect to litigation, claims and contractual agreements arising in the ordinary course of business. On the basis of management's assessment of the ultimate amount and timing of possible adverse outcomes and associated costs, none of such matters is presently expected to have a material adverse effect on the Company's consolidated financial condition, liquidity or results of operations.

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15. Financial Instruments and Commodity Hedging

Fair values of debt and other long-term instruments - The estimated fair value of the Company's long-term debt at June 30, 2003, including the current portion, was approximately $3.39 billion. The fair value was based on the discounted amounts of future cash outflows using the rates offered to the Company for debt with similar remaining maturities.

The estimated fair value of Unocal Capital Trust's 6 1/4 % convertible preferred securities was approximately $501 million at June 30, 2003. The fair value was based on the closing trading price of the preferred securities on June 30, 2003.

Commodity hedging activities - The Company uses hydrocarbon derivatives to mitigate its overall exposure to fluctuations in hydrocarbon commodity prices. The Company recognized $1 million of gains due to ineffectiveness for cash flow and fair value hedges in the second quarter and six months periods ended June 30, 2003. At June 30, 2003, the Company had approximately $15 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future commodity sales for the period beginning July 2003 through December 2004. Of this amount, approximately $13 million in after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months.

Foreign currency contracts - At June 30, 2003, the Company had approximately $1 million of after-tax deferred gains in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future foreign currency denominated payment obligations through December 2003. All of this amount is expected to be reclassified to the consolidated earnings statement during the next twelve months.

Interest rate contracts - The Company enters into interest rate swap contracts to manage its debt with the objective of minimizing the volatility and magnitude of the Company's borrowing costs. The Company may also enter into interest rate option contracts to protect its interest rate positions, depending on market conditions. At June 30, 2003, the Company had approximately $24 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges of interest rate exposures through September 2012. Of this amount, $3 million in after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months.

Credit Risk - Financial instruments that potentially subject the Company to concentrations of credit risks primarily consist of temporary cash investments and trade receivables. The Company places its temporary cash investments with high credit quality financial institutions and, by policy, limits the amount of credit exposure to any one financial institution. The concentration of trade receivable credit risk is generally limited due to the Company's customers being spread across industries in several countries. The Company's management has established certain credit requirements that its customers must meet before sales credit is extended. The Company monitors the financial condition of its customers to help ensure collections and to minimize losses.

16. Supplemental Condensed Consolidating Financial Information

Unocal guarantees all the publicly held securities issued by its 100 percent-owned subsidiaries Unocal Capital Trust and Union Oil. Such guarantees are full and unconditional and no subsidiaries of Unocal or Union Oil guarantee these securities.

The following tables present condensed consolidating financial information for (a) Unocal (Parent), (b) the Trust, (c) Union Oil (Parent) and (d) on a combined basis, the subsidiaries of Union Oil (non-guarantor subsidiaries). Virtually all of the Company's operations are conducted by Union Oil and its subsidiaries.

CONDENSED CONSOLIDATED EARNINGS STATEMENT
Three months ended June 30, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	E
Revenues					
Sales and operating revenues	$ -	$ -	$ 361	$ 1,525	
Interest, dividends and miscellaneous income	-	9	7	4	
Gain on sales of assets	-	-	43	4	
Total revenues	-	9	411	1,533	
Costs and other deductions					
Purchases, operating and other expenses	3	-	341	1,036	
Depreciation, depletion and amortization	-	-	78	177	
Impairments	-	-	3	-	
Dry hole costs	-	-	6	4	
Interest expense	9	1	29	7	
Distributions on convertible preferred securities	-	8	-	-	
Total costs and other deductions	12	9	457	1,224	
Equity in earnings of subsidiaries	187	-	224	-	
Earnings from equity investments	-	-	4	49	
Earnings from continuing operations before income taxes and minority interests	175	-	182	358	
Income taxes	(2)	-	3	132	
Minority interests	-	-	-	2	
Earnings from continuing operations	177	-	179	224	
Earnings from discontinued operations	-	-	8	-	
Net earnings	$ 177	$ -	$ 187	$ 224	

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CONDENSED CONSOLIDATED EARNINGS STATEMENT
Three months ended June 30, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	E
Revenues					
Sales and operating revenues	$ -	$ -	$ 286	$ 1,310	
Interest, dividends and miscellaneous income	-	9	-	10	
Gain on sales of assets	-	-	1	(2)	
Total revenues	-	9	287	1,318	
Costs and other deductions					
Purchases, operating and other expenses	1	-	259	848	
Depreciation, depletion and amortization	-	-	93	162	
Impairments	-	-	21	-	
Dry hole costs	-	-	2	11	

Interest expense	9	1	35	9
Distributions on convertible preferred securities	-	8	-	-
Total costs and other deductions	10	9	410	1,030
Equity in earnings of subsidiaries	118	-	198	-
Earnings from equity investments	-	-	2	49
Earnings from continuing operations before income taxes and minority interests	108	-	77	337
Income taxes	(3)	-	(41)	139
Minority interests	-	-	-	1
Earnings from continuing operations	111	-	118	197
Earnings from discontinued operations	-	-	-	1
Cumulative effects of accounting changes	-	-	-	-
Net earnings	$ 111	$ -	$ 118	$ 198

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the six months ended June 30, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	E
Revenues					
Sales and operating revenues	$ -	$ -	$ 873	$ 3,215	
Interest, dividends and miscellaneous income	-	17	18	6	
Gain on sales of assets	-	-	34	16	
Total revenues	-	17	925	3,237	
Costs and other deductions					
Purchases, operating and other expenses	5	-	623	2,247	
Depreciation, depletion and amortization	-	-	184	331	
Impairments	-	-	3	-	
Dry hole costs	-	-	58	23	
Interest expense	17	1	59	17	
Distributions on convertible preferred securities	-	16	-	-	
Total costs and other deductions	22	17	927	2,618	
Equity in earnings of subsidiaries	329	-	435	-	
Earnings from equity investments	-	-	7	89	
Earnings from continuing operations before income taxes and minority interests	307	-	440	708	
Income taxes	(4)	-	34	271	
Minority interests	-	-	-	4	
Earnings from continuing operations	311	-	406	433	
Earnings from discontinued operations	-	-	8	-	
Cumulative effects of accounting changes	-	-	(85)	2	

Net earnings	$ 311	$ -	$ 329	$ 435

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the six months ended June 30, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries
Revenues				
Sales and operating revenues	$ -	$ -	$ 495	$ 2,302
Interest, dividends and miscellaneous income	-	17	7	15
Gain on sales of assets	-	-	14	(13)
Total revenues	-	17	516	2,304
Costs and other deductions				
Purchases, operating and other expenses	3	-	486	1,493
Depreciation, depletion and amortization	-	-	180	299
Impairments	-	-	21	-
Dry hole costs	-	-	17	24
Interest expense	17	1	78	18
Distributions on convertible preferred securities	-	16	-	-
Total costs and other deductions	20	17	782	1,834
Equity in earnings of subsidiaries	148	-	326	-
Earnings from equity investments	-	-	2	86
Earnings from continuing operations before income taxes and minority interests	128	-	62	556
Income taxes	(7)	-	(86)	228
Minority interests	-	-	-	3
Earnings from continuing operations	135	-	148	325
Earnings from discontinued operations	-	-	-	1
Cumulative effects of accounting changes	-	-	-	-
Net earnings	$ 135	$ -	$ 148	$ 326

CONDENSED CONSOLIDATED BALANCE SHEET
At June 30, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	E
Assets					
Current assets					
Cash and cash equivalents	$ -	$ -	$ 150	$ 213	$

Accounts and notes receivable - net	59	-	260	751	
Inventories	-	-	15	86	
Other current assets	-	-	118	34	
Total current assets	59	-	543	1,084	
Investments and long-term receivables - net	4,891	-	4,958	1,000	
Properties - net	-	-	2,244	6,086	
Other assets including goodwill	4	541	25	(55)	
Total assets	$4,954	$ 541	$ 7,770	$ 8,115	$
Liabilities and Stockholders' Equity					
Current liabilities					
Accounts payable	$ -	$ -	$ 262	$ 847	$
Current portion of long-term debt and capital leases	-	-	215	17	
Other current liabilities	51	3	296	276	
Total current liabilities	51	3	773	1,140	
Long-term debt and capital leases	-	-	2,088	656	
Deferred income taxes	-	-	(150)	827	
Accrued abandonment, restoration and environmental liabilities	-	-	471	446	
Other deferred credits and liabilities	541	-	459	(149)	
Minority interests	-	-	-	317	
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	-	522	-	-	
Stockholders' equity	4,362	16	4,129	4,878	
Total liabilities and stockholders' equity	$4,954	$ 541	$ 7,770	$ 8,115	$

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CONDENSED CONSOLIDATED BALANCE SHEET
At December 31, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	E
Assets					
Current assets					
Cash and cash equivalents	$ -	$ -	$ (18)	$ 186	$
Accounts and notes receivable - net	54	-	276	738	
Inventories	-	-	10	87	
Other current assets	1	-	85	30	
Total current assets	55	-	353	1,041	
Investments and long-term receivables - net	4,562	-	4,513	960	
Properties - net	-	-	2,255	5,624	
Other assets including goodwill	3	541	272	(12)	
Total assets	$4,620	$ 541	$ 7,393	$ 7,613	$

Liabilities and Stockholders' Equity					
Current liabilities					
Accounts payable	$ -	$ -	$ 290	$ 788	$
Current portion of long-term debt and capital leases	-	-	-	6	
Other current liabilities	44	3	120	455	
Total current liabilities	44	3	410	1,249	
Long-term debt and capital leases	-	-	2,418	584	
Deferred income taxes	-	-	(116)	709	
Accrued abandonment, restoration and environmental liabilities	-	-	320	302	
Other deferred credits and liabilities	541	-	424	184	
Minority interests	-	-	-	313	
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	-	522	-	-	
Stockholders' equity	4,035	16	3,937	4,272	
Total liabilities and stockholders' equity	$4,620	$ 541	$ 7,393	$ 7,613	$

CONDENSED CONSOLIDATED CASH FLOWS
For the six months ended June 30, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	E
Cash Flows from Operating Activities	$ 93	$ -	$ 389	$ 603	
Cash Flows from Investing Activities					
Capital expenditures and acquisitions (includes dry hole costs)	-	-	(223)	(694)	
Proceeds from sales of assets and discontinued operations	-	-	123	68	
Net cash used in investing activities	-	-	(100)	(626)	
Cash Flows from Financing Activities					
Change in long-term debt and capital leases	-	-	(114)	50	
Dividends paid on common stock	(103)	-	-	-	
Minority interests	-	-	-	(3)	
Other	10	-	(7)	3	
Net cash provided by (used in) financing activities	(93)	-	(121)	50	
Increase in cash and cash equivalents	-	-	168	27	
Cash and cash equivalents at beginning of period	-	-	(18)	186	
Cash and cash equivalents at end of period	$ -	$ -	$ 150	$ 213	

CONDENSED CONSOLIDATED CASH FLOWS
For the six months ended June 30, 2002

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	E
Cash Flows from Operating Activities	$ 80	$ -	$ (110)	$ 656	
Cash Flows from Investing Activities					
Capital expenditures and acquisitions (includes dry hole costs)	-	-	(213)	(617)	
Proceeds from sales of assets and discontinued operations	-	-	15	32	
Net cash used in investing activities	-	-	(198)	(585)	
Cash Flows from Financing Activities					
Change in long-term debt and capital leases	-	-	307	(96)	
Dividends paid on common stock	(98)	-	-	-	
Minority interests	-	-	-	(4)	
Other	19	-	-	-	
Net cash provided by (used in) financing activities	(79)	-	307	(100)	
Increase (decrease) in cash and cash equivalents	1	-	(1)	(29)	
Cash and cash equivalents at beginning of period	-	-	62	128	
Cash and cash equivalents at end of period	$ 1	$ -	$ 61	$ 99	

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17. Segment Data

The Company's reportable segments are: Exploration and Production, Trade, Midstream, and Geothermal and Power Operations. General corporate overhead, unallocated costs and other miscellaneous operations, including real estate, carbon and minerals and activities relating to businesses that were sold, are included under the Corporate and Other heading.

Segment Information For the Three Months ended June 30, 2003	Exploration & Productio			
	North America			Int
Millions of dollars	U.S. Lower 48	Alaska	Canada	Far E
Sales & operating revenues	$ 141	$ 62	$ 37	$ 2
Other income (loss) (a)	46	-	-	
Inter-segment revenues	284	-	41	
Total	471	62	78	3

Earnings from equity investments	6	-	-	
Earnings (loss) from continuing operations	89	14	8	1
Earnings from discontinued operations	-	-	-	
Net earnings (loss)	89	14	8	1
Assets (at June 30, 2003)	3,245	329	1,318	3,0

	Midstream	Geothermal & Power Operations	Corporate & Other Admin & General	Net Interest Expense	Enviro & Liti
Sales & operating revenues	$ 128	$ 28	$ -	$ -	$
Other income (loss) (a)	1	2	-	6	
Inter-segment revenues	2	-	-	-	
Total	131	30	-	6	
Earnings from equity investments	17	4	-	-	
Earnings (loss) from continuing operations	18	7	(22)	(28)	(
Earnings from discontinued operations	-	-	-	-	
Net earnings (loss)	18	7	(22)	(28)	(
Assets (at June 30, 2003)	596	535	-	-	

Segment Information For the Three Months ended June 30, 2002 Millions of dollars	Exploration & Productio North America U.S. Lower 48	Alaska	Canada	Int Far E
Sales & operating revenues	$ 123	$ 73	$ 63	$ 2
Other income (loss) (a)	2	-	-	
Inter-segment revenues	234	-	-	
Total	359	73	63	3
Earnings from equity investments	1	-	-	
Earnings (loss) from continuing operations	20	(5)	6	1
Earnings from discontinued operations	-	-	-	
Net earnings (loss)	20	(5)	6	1
Assets (at December 31, 2002)	3,358	326	1,113	2,8

	Midstream	Geothermal & Power Operations	Corporate & Other Admin & General	Net Interest Expense	Enviro & Liti
Sales & operating revenues	$ 74	$ 33	$ -	$ -	$
Other income (loss) (a)	-	2	-	5	
Inter-segment revenues	4	-	-	-	
Total	78	35	-	5	
Earnings from equity investments	18	5	-	-	
Earnings (loss) from continuing operations	23	14	(19)	(28)	(
Earnings from discontinued operations	-	-	-	-	
Net earnings (loss)	23	14	(19)	(28)	(
Assets (at December 31, 2002)	511	526	-	-	

Segment Information For the Six Months ended June 30, 2003 Millions of dollars	Exploration & Productio North America U.S. Lower 48	Alaska	Canada	Int Far E
Sales & operating revenues	$ 302	$128	$ 95	$ 6
Other income (loss) (a)	49	-	-	
Inter-segment revenues	672	-	79	1
Total	1,023	128	174	7
Earnings from equity investments	9	-	-	
Earnings (loss) from continuing operations	200	29	32	2
Earnings from discontinued operations	-	-	-	
Cumulative effect of accounting change (b)	11	(43)	4	
Net earnings (loss)	211	(14)	36	2
Assets (at June 30, 2003)	3,245	329	1,318	3,0

	Midstream	Geothermal & Power Operations	Corporate & Other Admin & General	Net Interest Expense	Enviro & Liti
Sales & operating revenues	$ 269	$ 63	$ -	$ -	$
Other income (loss) (a)	2	2	-	10	

Inter-segment revenues	4	-	-	-	
Total	275	65	-	10	
Earnings from equity investments	32	5	-	-	
Earnings (loss) from continuing operations	36	19	(45)	(59)	(
Earnings from discontinued operations	-	-	-	-	
Cumulative effect of accounting change (b)	(2)	-	-	-	
Net earnings (loss)	34	19	(45)	(59)	(
Assets (at June 30, 2003)	596	535	-	-	

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Segment Information For the Six Months ended June 30, 2002 Millions of dollars	Exploration & Productio			
	North America			Int
	U.S. Lower 48	Alaska	Canada	Far E
Sales & operating revenues	$ 237	$124	$103	$ 5
Other income (loss) (a)	5	-	-	
Inter-segment revenues	400	-	-	1
Total	642	124	103	6
Earnings from equity investments	-	-	-	
Earnings (loss) from continuing operations	24	(11)	(3)	2
Earnings from discontinued operations	-	-	-	
Net earnings (loss)	24	(11)	(3)	2
Assets (at December 31, 2002)	3,358	326	1,113	2,8

	Midstream	Geothermal & Power Operations	Corporate & Other		
			Admin & General	Net Interest Expense	Enviro & Liti
Sales & operating revenues	$ 136	$ 61	$ -	$ -	$
Other income (loss) (a)	1	4	-	8	
Inter-segment revenues	6	-	-	-	
Total	143	65	-	8	
Earnings from equity investments	37	2	-	-	
Earnings (loss) from continuing operations	42	20	(43)	(65)	(
Earnings from discontinued operations	-	-	-	-	
Net earnings (loss)	42	20	(43)	(65)	(

Assets (at December 31, 2002)	511	526	-	-

18. Subsequent Event

In 1999, the Company contributed fixed-price overriding royalty interests from its working interest shares in certain oil and gas producing properties in the Gulf of Mexico to Spirit LP. In exchange for its overriding royalty contributions, valued at $304 million, the Company received an initial general partnership interest in Spirit LP of approximately 55 percent. An unaffiliated investor contributed $250 million in cash to the partnership in exchange for an initial limited partnership interest of approximately 45 percent.

In June, 2003 the Company entered into an agreement to pay the limited partner for its minority interest in Spirit LP, the amount of which was $252 million. In July, 2003 the agreement was executed and the payment was made. At June 30, 2003, minority interests on the Company's balance sheet included the $252 million related to Spirit LP. In the third quarter of 2003, FASB Interpretation No. 46 would have required the Company to consolidate the limited partner, an unaffiliated investor, which would have resulted in a reclassification of $242 million of minority interests to long-term debt.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion and analysis of the consolidated financial condition and results of operations of the Company should be read in conjunction with Management's Discussion and Analysis in Item 7 of Unocal's 2002 Annual Report on Form 10-K.

CONSOLIDATED RESULTS

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Millions of dollars	2003	2002	2003	2002
Earnings from continuing operations	$ 169	$ 113	$ 386	$ 135
Earnings from discontinued operations	8	1	8	1
Cumulative effects of accounting changes	-	-	(83)	-
Net earnings	$ 177	$ 114	$ 311	$ 136

Continuing Operations

Second Quarter Results: Earnings from continuing operations increased by $56 million in the second quarter of 2003 compared to the same quarter a year ago, primarily reflecting improved results from the Company's exploration and production operations, due to higher worldwide natural gas and liquids prices. Higher worldwide commodity prices increased net earnings by approximately $90 million. The Company's worldwide average realized natural gas price, including a loss of 7 cents per Mcf from hedging activities, was $3.53 per Mcf for the current quarter. This was an increase of 66 cents per Mcf, or 23 percent, from the $2.87 per Mcf realized during the same period a year ago. In the current quarter, the Company's worldwide average realized liquids price was $25.36 per Bbl, which was an increase of $2.11 per Bbl, or 9 percent, from the same period a year ago. The Company's hedging program lowered the average realized liquids price by 4 cents per Bbl in the current quarter while the second quarter of the prior year included a loss of one cent per Bbl from hedging activities. In the current quarter, International production contributed approximately $29 million in higher earnings. The largest contributor to the higher International production was Thailand, where oil-equivalent production was up 10 percent from last year's second quarter. Crude oil and condensate production increased 29 percent, primarily because of de-bottlenecking production from the Yala-Plamuk oil project and higher condensate production from the Pailin Phase 2 project. Quarterly natural gas production increased 5 percent from last year due to increased demand tied to higher electric power needs and reduced volumes from other suppliers. The Company functions as the "swing producer" in Thailand, providing above-contract minimum volumes when required to meet Thailand's needs. The Company has routinely produced more than its contract minimums. Higher production from Azerbaijan and Bangladesh also contributed to increases in International production. In addition, the Company recorded a $20 million after-tax gain from the sale of its interest in Matador Petroleum Corporation ("Matador"), which was accounted for as an equity investment.

These positive variance factors were partially offset by lower North America production and higher amortization of exploratory leasehold costs, which reduced net earnings by approximately $25 million and $16 million, respectively, in the current quarter compared with the same period a year ago. North America liquids production averaged 84,000 Bbl/d in the current quarter, down from 96,000 Bbl/d in the same period a year ago, while natural gas production averaged 805 MMcf/d in the current quarter, down from 935 MMcf/d in the same period a year ago. Most of the production decline was due to natural declines in existing fields in the Gulf of Mexico and the divestiture of various properties in Canada, onshore U.S. and the Gulf of Mexico. The higher amortization of exploratory leasehold costs is primarily a result of the anticipated relinquishment of about 45 deepwater Gulf of Mexico blocks before their expiration dates.

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Higher pension related expenses also reduced net earnings by approximately $11 million in the current quarter compared to the same period a year ago. In addition, the Company recorded a $17 million after-tax ($27 million pre-tax) restructuring charge aimed at strengthening the Company's Lower 48 businesses, realigning its corporate staff and shared resource groups, and improving its balance sheet. In the second quarter of 2002, the Company recorded a $12 million after-tax ($19 million pre-tax) restructuring charge in its Gulf Region business unit.

The second quarters of 2003 and 2002 both included after-tax gains of $2 million and $4 million, respectively, in mark-to-market accruals and realized gains/losses for non-hedge commodity derivatives recorded by the Company's Northrock Resources Ltd. ("Northrock") subsidiary. After-tax environmental and litigation expenses were $29 million in the current quarter of 2003, compared with $15 million in the same period a year ago.

Six Months Results: Earnings from continuing operations were $386 million in the first six months of 2003 compared to $135 million for the same period a year ago. The increase was primarily due to higher worldwide natural gas and liquids prices. Higher worldwide commodity prices increased net earnings by approximately $310 million. The Company's worldwide average realized natural gas price, including a loss of 17 cents per Mcf from hedging activities, was $3.71 per Mcf in the first six months of 2003. This was an increase of $1.03 per Mcf, or 38 percent, from the $2.68 per Mcf, including a benefit of 6 cents per Mcf from hedging activities, realized during the first six months of 2002. In the first six months of 2003, the Company's worldwide average realized liquids price was $27.54 per Bbl, which was an increase of $6.41 per Bbl, or 30 percent, from the same period a year ago. The Company's hedging program lowered the average realized liquids price by 26 cents per Bbl in the first six months of 2003 while the first six months of 2002 included a gain of 2 cents per Bbl from hedging activities. International production also contributed approximately $37 million in higher earnings, primarily from the higher Thailand production. The first six months of 2003 included the $20 million after-tax gain on the sale of the equity interest in Matador and an after-tax gain of $4 million in mark-to-market accruals and realized gains/losses for non-hedge commodity derivatives recorded by the Company's Northrock subsidiary. The results in the first six months of 2002 included a $12 million after-tax impairment in Alaska.

These 2003 positive variance factors were partially offset by lower North America production, higher dry hole costs in the Gulf of Mexico, higher pension related expenses and the higher amortization of exploratory leasehold costs, which reduced net earnings by approximately $30 million, $24 million, $19 million and $16 million, respectively, in the first six months of 2003 compared with the same period a year ago. North America liquids production averaged 85,000 Bbl/d in the first six months of 2003, down from 98,000 Bbl/d a year ago, while natural gas production averaged 833 MMcf/d down from 934 MMcf/d for the six months period a year ago. Most of the production decline was due to natural declines in existing fields in the Gulf of Mexico and the divestiture of various properties in Canada, onshore U.S. and the Gulf of Mexico. After-tax environmental and litigation expenses were $46 million in the first six months of 2003, compared with $38 million in the same period a year ago. The first six months of 2003 included the company-wide $17 million restructuring charge, while the same period a year ago included a $12 million restructuring charge for the Gulf Region business unit.

Cumulative Effects of Accounting Changes

In the first quarter of 2003, the Company recorded a non-cash $83 million after-tax charge consisting of the cumulative effect of a change in accounting principle related to the initial adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations." The Company also increased its accrued abandonment and restoration liabilities by $268 million and increased its net properties by $138 million on the consolidated balance sheet as a result of the adoption of SFAS No.143.

Revenues

Revenues from continuing operations for the second quarter of 2003 were $1.62 billion compared with $1.37 billion for the same period a year ago. In the first six months of 2003, total revenues from continuing operations were $3.41 billion compared with $2.42 billion for the same period a year ago. The increases, in both the quarter and six months amounts, primarily reflected higher crude oil and natural gas prices.

OPERATING HIGHLIGHTS	For the Three Months Ended June 30,	For the Six Months Ended June 30,

	2003	2002	2003	2002
North America Net Daily Production				
Liquids (thousand barrels)				
U.S. Lower 48 (a) (b)	44	54	46	55
Alaska	23	25	22	25
Canada	17	17	17	18
Total liquids	84	96	85	98
Natural gas - dry basis (million cubic feet)				
U.S. Lower 48 (a) (b)	652	766	678	754
Alaska	67	77	64	89
Canada	86	92	91	91
Total natural gas	805	935	833	934
North America Average Prices (excluding hedging activities) (c)				
Liquids (per barrel)				
U. S. Lower 48	$ 26.02	$ 23.49	$ 28.11	$ 20.95
Alaska	$ 27.46	$ 24.74	$ 31.34	$ 21.99
Canada	$ 23.52	$ 21.92	$ 26.05	$ 19.15
Average	$ 25.93	$ 23.56	$ 28.48	$ 20.89
Natural gas (per mcf)				
U. S. Lower 48	$ 5.01	$ 3.12	$ 5.66	$ 2.68
Alaska	$ 1.20	$ 1.57	$ 1.20	$ 1.57
Canada	$ 5.13	$ 3.03	$ 5.40	$ 2.54
Average	$ 4.69	$ 2.98	$ 5.27	$ 2.55
North America Average Prices (including hedging activities) (c)				
Liquids (per barrel)				
U. S. Lower 48	$ 25.84	$ 23.48	$ 27.22	$ 21.01
Alaska	$ 27.46	$ 24.74	$ 31.34	$ 21.99
Canada	$ 23.52	$ 21.92	$ 26.05	$ 19.15
Average	$ 25.84	$ 23.56	$ 27.99	$ 20.92
Natural gas (per mcf)				
U. S. Lower 48	$ 4.86	$ 3.12	$ 5.23	$ 2.80
Alaska	$ 1.20	$ 1.57	$ 1.20	$ 1.57
Canada	$ 4.79	$ 2.97	$ 5.07	$ 2.62
Average	$ 4.53	$ 2.97	$ 4.89	$ 2.66

OPERATING HIGHLIGHTS (CONTINUED)	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2003	2002	2003	2002
International Net Daily Production (d)				
Liquids (thousand barrels)				
Far East	59	54	57	53
Other (a)	20	20	21	20
Total liquids	79	74	78	73
Natural gas - dry basis (million cubic feet)				

Far East	911	883	890	852
Other (a)	89	79	100	78
Total natural gas	1,000	962	990	930
International Average Prices (d)(e)				
Liquids (per barrel)				
Far East	$ 24.78	$ 22.50	$ 27.06	$ 20.95
Other	$ 25.16	$ 23.91	$ 27.11	$ 23.03
Average	$ 24.90	$ 22.84	$ 27.07	$ 21.43
Natural gas (per mcf)				
Far East	$ 2.74	$ 2.78	$ 2.75	$ 2.70
Other	$ 2.89	$ 2.79	$ 2.86	$ 2.64
Average	$ 2.76	$ 2.78	$ 2.76	$ 2.69
Worldwide Net Daily Production (a) (b) (d)				
Liquids (thousand barrels)	163	170	163	171
Natural gas-dry basis (million cubic feet)	1,805	1,897	1,823	1,864
Barrels oil equivalent (thousands)	463	486	467	482
Worldwide Average Prices (excluding hedging activities) (c)				
Liquids (per barrel)	$ 25.40	$ 23.26	$ 27.80	$ 21.11
Natural gas (per mcf)	$ 3.60	$ 2.87	$ 3.88	$ 2.62
Worldwide Average Prices (including hedging activities) (c) (e)				
Liquids (per barrel)	$ 25.36	$ 23.25	$ 27.54	$ 21.13
Natural gas (per mcf)	$ 3.53	$ 2.87	$ 3.71	$ 2.68

Selected Costs and Other Deductions

Administrative and general expense in the second quarter of 2003 included a $27 million pre-tax charge as a result of the restructuring program announced in June that is aimed at strengthening the Company's Lower 48 businesses, realigning its corporate staff and shared resource groups, and improving its balance sheet. The higher administrative and general expense category also reflected higher pension-related expenses.

Exploration expense was higher in the second quarter of 2003 primarily from higher amortization of leasehold costs of $26 million pre-tax that were a result of the Company's anticipated relinquishment of about 45 deepwater Gulf of Mexico blocks before their expiration dates. This reflects the decision to focus the Company's deepwater Gulf of Mexico land position on those OCS blocks that have the best potential.

Exploration and Production

The Company engages in oil and gas exploration, development and production worldwide. The results of this segment are discussed under the geographical breakdown of North America and International:

North America - Included in this category are the U.S. Lower 48, Alaska and Canada oil and gas operations. The emphasis of the U.S. Lower 48 operations is on the onshore, the shelf and deepwater areas of the Gulf of Mexico region and the Permian and San Juan Basins in west Texas and New Mexico. A substantial portion of the crude oil and natural gas produced in the U.S. Lower 48 operations is sold to the Company's Trade business segment. Natural gas produced by Northrock in Canada is also sold to the Company's Trade business segment. The remainder of U.S. Lower 48 and Canada production is sold to third parties. In Alaska, natural gas production, pursuant to agreements with the purchaser of the Company's former agricultural products business, is sold to a fertilizer plant in Nikiski, Alaska. In addition, the Company uses hydrocarbon derivative financial instruments such as futures, swaps and options to hedge portions of the Company's exposure to commodity price fluctuations.

Second Quarter Results: Earnings from continuing operations were $111 million in the second quarter of 2003 compared to $21 million for the same period a year ago, which was an increase of $90 million. The increase was primarily due to higher natural gas and liquids prices, which increased net earnings by approximately $82 million. The Company also recorded a $20 million after-tax gain from the sale of its interest in Matador. These positive factors were partially offset by lower natural gas and liquids production, and higher amortization of exploratory leasehold costs, which reduced after-tax earnings by approximately $25 million and $16 million, respectively. The second quarters of 2003 and 2002 included after-tax gains of $2 million and $4 million, respectively, in mark-to-market accruals and realized gains/losses for non-hedge commodity derivatives recorded by the Company's Northrock subsidiary. The second quarter of 2002 included a $12 million after-tax impairment in the Alaska business unit and a $12 million after-tax restructuring charge in the Gulf Region business unit.

Six Months Results: Earnings from continuing operations were $261 million in the first six months of 2003 compared to $10 million for the same period a year ago. The increase was primarily due to higher natural gas and liquids prices, which increased net earnings by approximately $263 million. In addition, the Company recorded the $20 million gain from the sale of its interest in Matador. These positive factors were partially offset by lower natural gas and liquids production, higher dry hole costs, and higher exploratory land provisions, which reduced after-tax earnings by approximately $30 million, $23 million and $18 million, respectively. The six months period of 2002 included the $12 million after-tax impairment in the Alaska business unit and the $12 million after-tax restructuring charge in the Gulf Region business unit. The first six months of 2003 included the after-tax gain of $4 million in mark-to-market accruals and realized gains/losses for non-hedge commodity derivatives recorded by the Company's Northrock subsidiary.

International - Unocal's International operations include oil and gas exploration and production activities outside of North America. The Company operates or participates in production operations in Thailand, Indonesia, Myanmar, Bangladesh, the Netherlands, Azerbaijan, the Democratic Republic of Congo and Brazil. International operations also include the Company's exploration activities and the development of energy projects primarily in Asia, Australia, Latin America and West Africa.

Second Quarter Results: Earnings from continuing operations totaled $145 million in the current quarter compared to $125 million in the same period a year ago, which was an increase of $20 million. The increase was primarily due to $26 million in higher liquids production and $8 million in higher liquids prices. Higher International liquids production was mainly from Thailand due to de-bottlenecking production from the Yala-Plamuk oil project and higher condensate production from the Pailin Phase 2 project. These positive factors were partially offset by approximately $7 million in higher DD&A expense (including asset retirement obligation accretion).

Six Months Results: Earnings from continuing operations totaled $287 million in the first six months of 2003 compared to $227 million in the same period a year ago, which was an increase of $60 million. The increase was primarily due to $40 million in higher liquids prices and $37 million in higher liquids and natural gas production. These positive factors were partially offset by approximately $23 million in higher DD&A expense (including asset retirement obligation accretion). The higher natural gas production was primarily from increased demand tied to higher electric power needs in Thailand and higher production in Bangladesh. Higher liquids production was due to the aforementioned Yala-Plamuk and Pailin Phase 2 projects in Thailand.

TRADE

The Trade segment externally markets the majority of the Company's worldwide liquids production and North American natural gas production, excluding production of the Alaska business unit. It is also responsible for executing various derivative contracts on behalf of the Exploration and Production segment in order to manage the Company's exposures to commodity price changes. The Trade segment also purchases liquids and natural gas from certain of the Company's royalty owners, joint venture partners and unaffiliated oil and gas producing and trading companies for resale. In addition, the segment trades hydrocarbon derivative instruments, for which hedge accounting is not used, to exploit anticipated opportunities arising from commodity price fluctuations. The segment also purchases limited amounts of physical inventories for energy trading purposes when arbitrage opportunities arise. These commodity risk-management and trading activities are subject to internal restrictions, including value at risk limits, which measure the Company's potential loss from likely changes in market prices.

Second Quarter Results: Earnings from continuing operations totaled $4 million in the current quarter compared to $1 million in the same period a year ago. The higher results reflect gains from crude oil and natural gas trading activities, which were positively impacted by volatile commodity prices.

Sales and operating revenues from the Trade business segment were $738 million in the current quarter compared to $644 million in the same quarter a year ago, which was an increase of $94 million. These revenues represented approximately 47 percent and 48 percent of the Company's total sales and operating revenues for the second quarters of 2003 and 2002, respectively. Natural gas revenues, as a result of higher prices, constituted the majority of the increase.

Six Months Results: The results for the first six months were a loss of $5 million compared to earnings of $2 million in the same period a year ago. The decrease was primarily due to lower results related to domestic natural gas and crude oil marketing activities, which were negatively impacted by volatile commodity prices.

Sales and operating revenues were $1.66 billion in the first six months of 2003 compared to $1.1 billion in the same period a year ago, which was an increase of $558 million. These revenues represented approximately 50 percent and 46 percent of the Company's total sales and operating revenues for the first six months of 2003 and 2002, respectively. In the first six months of 2003, natural gas revenues increased by approximately $360 million and crude oil revenues increased by approximately $200 million, primarily due to higher commodity prices, as compared to the same period a year ago.

MIDSTREAM

The Midstream segment is comprised of the Company's equity interests in certain petroleum pipeline companies, wholly-owned pipeline systems throughout the U.S., and the Company's North America gas storage business.

Second Quarter Results: Earnings from continuing operations totaled $18 million in the current quarter compared to $23 million in the same period a year ago. The decrease was due primarily to $4 million in lower results from the pipelines business, which resulted from lower throughput volumes and the divestiture from certain of the Company's pipeline interests.

Six Months Results: Earnings from continuing operations totaled $36 million in the first six months of 2003 compared to $42 million in the same period a year ago. The decrease was due primarily to $6 million in lower results from the pipelines business and $3 million from expenses related to the Baku-Tbilisi-Ceyhan pipeline project. These negative factors were partially offset by improved results in the gas storage business.

GEOTHERMAL AND POWER OPERATIONS

The Geothermal and Power Operations business segment produces geothermal steam for power generation, with operations in the Philippines and Indonesia. The segment's activities also include the operation of geothermal steam-fired power plants in Indonesia and equity interests in gas-fired power plants in Thailand. The Company's non-exploration and production business development activities, primarily power-related, are also included in this segment.

Second Quarter Results: Earnings from continuing operations totaled $7 million in the current quarter compared to $14 million in the same period a year ago. The lower current period results were primarily impacted by lost steam sales and higher operating expenses necessitated by repairs to facilities damaged by major flooding and landslides at the Company's Salak geothermal project area in Indonesia.

Six Months Results: Earnings from continuing operations totaled $19 million in the first six months of 2003 compared to $20 million in the same period a year ago. The period results included the losses attributable to the flooding and landslides discussed above, which were partially offset by lower non-exploration and production business development expenses as compared to the same period a year ago.

CORPORATE AND OTHER

Corporate and Other includes general corporate overhead, miscellaneous operations (including real estate activities, carbon and minerals) and other corporate unallocated costs (including environmental and litigation expense). Net interest expense represents interest expense, net of interest income and capitalized interest.

Second Quarter Results: The results for the current quarter were a loss of $116 million compared to a loss of $71 million in the same period a year ago. The current quarter included the $17 million restructuring charge (see note 4 to the consolidated financial statements in Item 1 of this report). After-tax expenses for environmental and litigation matters for the current quarter were $28 million compared to $13 million after-tax for the same period a year ago. In addition, the current quarter reflected approximately $13 million after-tax in higher pension related expenses.

Six Months Results: The results for the first six months were a loss of $212 million compared to a loss of $166 million in the same period a year ago. The first six months of 2003 included the $17 million restructuring charge and higher pension related expenses of $17 million. After-tax expenses for environmental and litigation matters for the six months of 2003 were $45 million compared to $36 million after-tax for the same period a year ago. Net interest expense was $6 million lower in the first six months of 2003 compared to the same period a year ago, primarily due to higher capitalized interest on development projects.

FINANCIAL CONDITION

Cash flows from operating activities, including working capital and other changes, were $1.09 billion for the six months ended June 30, 2003, compared with $626 million for the same period a year ago. The increase principally reflected the effects of higher worldwide commodity prices. The positive impact from higher prices was partially offset by higher income tax payments, compared to the same period a year ago, and the repayment of the outstanding balance of certain domestic trade receivables sold under the Company's accounts receivable securitization program.

Pre-tax proceeds from asset sales were $191 million for the six months ended June 30, 2003. The Company received $80 million from the sale of its equity interest in Matador. The Company also completed the sale of various properties in Canada, onshore U.S. and the Gulf of Mexico, which netted the Company approximately $105 million in proceeds. Pre-tax proceeds from asset sales including those classified as discontinued operations were $47 million for the six months ended June 30, 2002. These proceeds included $27 million from the sale of oil and gas producing properties in the U.S. by the Company's Pure subsidiary, while the remaining $20 million were from various other oil and gas asset sales and other miscellaneous properties.

Capital expenditures were $917 million for the first six months of 2003 compared with $830 million in the same period a year ago. Capital expenditures for 2003 are currently forecast at approximately $1.73 billion, essentially unchanged from 2002. Capital expenditures reflect higher development projects, including the Caspian crude oil development and the Baku-Tbilisi-Ceyhan ("BTC") pipeline project, the West Seno field in deepwater Indonesia and Mad Dog in the Gulf of Mexico. In the first six months of 2003, the Company's capital expenditures included approximately $405 million for the development of undeveloped proved oil and gas reserves, primarily in Indonesia, Azerbaijan, Thailand and the deepwater Gulf of Mexico.

The Company's total consolidated debt, including current maturities, at June 30, 2003, was $3.0 billion, basically unchanged from the end of 2002. During the first six months of 2003, the Company retired $89 million in 9.25% debentures and paid down $10 million of medium-term notes which matured. The Company also repurchased $15 million of the $200 million outstanding balance in 6.375% notes due in 2004 and repaid $20 million of 6.20% Industrial Development Revenue Bonds. These decreases were partially offset by $79 million drawn under the Overseas Private Investment Corporation ("OPIC") Financing Agreement for the first phase of the West Seno project in Indonesia (see note 11 for further detail on the Company's long-term debt). Cash and cash equivalents on hand totaled $363 million at June 30, 2003, up from $168 million at the end of 2002. The Company's long-term debt ratings remain stable.

The Company has two credit facilities in place: a $400 million 364-day credit agreement and a $600 million 5-year credit agreement, maturing October 2006. The agreements provide for the termination of the loan commitments and require the prepayment of all outstanding borrowings in the event that (1) any person or group becomes the beneficial owner of more than 30 percent of the then outstanding voting stock of Unocal other than in a transaction having the approval of Unocal's board of directors, at least a majority of which are continuing directors, or (2) if continuing directors shall cease to constitute at least a majority of the board. The agreements do not have drawdown restrictions or prepayment obligations in the event of a credit rating downgrade. Both agreements limit the Company's total debt to total capitalization ratio to 70 percent (total capitalization is defined as total debt plus total equity, with the Company's convertible preferred securities included as equity in the ratio calculation.) In addition, the Company also has a 3-year $295 million Canadian dollar-denominated non-revolving credit facility with a variable rate of interest. At June 30, 2003, the borrowing under the credit facility translated to $218 million, using applicable foreign exchange rates.

Based on current commodity prices and current development projects, the Company expects cash generated from operating activities, asset sales and cash on hand in 2003 to be sufficient to cover its operating and capital spending requirements and to meet dividend payments and to pay down debt. The Company paid off the $252 million limited partner interest in Spirit Energy 76 Development, L.P. in July. This financing would have been reclassified from minority interests to debt in the third quarter pursuant to Financial Accounting Standards Board Interpretation 46 ("Consolidation of Variable Interest Entities"). Further, the Company has substantial borrowing capacity to enable it to meet unanticipated cash requirements.

The Company relies on the commercial paper market, its accounts receivable securitization program and its revolving credit facilities to cover near-term borrowing requirements. At June 30, 2003, the Company did not have an outstanding balance under its accounts receivable securitization program, which was at the $108 million level at year-end 2002. The Company also had in place a universal shelf registration statement as of June 30, 2003, with an unutilized balance of approximately $1.539 billion, which is available for the future issuance of other debt and/or equity securities depending on the Company's needs and market conditions. From time to time, the Company may also look to fund some of its long-term projects using other financing sources, including multilateral and bilateral agencies.

Maintaining investment-grade credit ratings, that is "BBB- / Baa3" and above from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively, is a significant factor in the Company's ability to raise short-term and long-term financing. As a result of the Company's current investment grade ratings, the Company has access to both the commercial paper and bank loan markets. The Company currently has a BBB+ / Baa2 credit rating by Standard & Poor's and Moody's, respectively, and an A-2 / Prime-2 for its commercial paper ratings. Moody's and Standard & Poor's outlooks remained stable for the Company's long term debt and commercial paper ratings. The Company does not believe it has a significant exposure to liquidity risk in the event of a credit rating downgrade.

ENVIRONMENTAL MATTERS

The Company is committed to operating its business in a manner that is environmentally responsible. This commitment is fundamental to the Company's core values. As part of this commitment, the Company has procedures in place to audit and monitor its environmental performance. In addition, it has implemented programs to identify and address environmental risks throughout the Company. Costs associated with identified environmental remediation obligations have been accrued in a reserve for such obligations. At June 30, 2003, the Company's remediation reserve totaled $267 million, of which $121 million was included in current liabilities. During the six months period ended June 30, 2003, cash payments of $30 million were applied against the reserve and $52 million in provisions were added to the reserve. The Company may also incur additional liabilities in the future at sites where remediation liabilities are probable but future environmental costs are not presently reasonably estimable because the sites have not been assessed or the assessments have not advanced to stages where costs are reasonably estimable. At those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $205 million. The Company's total environmental reserve and possible additional liability amounts are grouped into the following four categories.

	At June 30, 2003	
Millions of dollars	Reserve	Possible Additional Costs
Superfund and similar sites	$ 17	$ 15
Active Company facilities	31	25
Company facilities sold with retained liabilities and former Company-operated sites	98	80
Inactive or closed Company facilities	121	85
Total	$ 267	$ 205

Also see notes 13 and 14 to the consolidated financial statements in Item 1 of this report for additional information on environmental related matters.

During the first six months of 2003, the Company recorded provisions of $40 million related to sites in the "Inactive or closed Company facilities" category primarily for the Guadalupe oil field located on the central California coast and for remediation projects at the Company's former refinery in Beaumont, Texas.

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For the Guadalupe oil field site, it was determined that contaminated soil excavated from the site will probably be taken to an offsite landfill for disposal. The soil is contaminated with diluent, a kerosene-like additive used in the field's former operations. Previously, the Company had planned to remediate the soil on-site; however, a preliminary draft report for the ecological risk study being conducted indicates that on-site remediation is not feasible. The provisions recorded for the site include the costs for the offsite disposal alternative. The provisions recorded for the Guadalupe oil field also include estimated costs for remediation work that is ongoing at the site. This work includes groundwater monitoring, operation and maintenance of remedial systems, restoration, agency oversight, permitting, and site assessment. The provisions for these costs are based on data from various studies and assessments that have been completed for the site in conjunction with data provided by the project management system the Company has in place.

A provision was also recorded for the Company's former Beaumont, Texas refinery. The Company has been working with the Texas Commission on Environmental Quality ("TCEQ") to develop plans for closing impoundments used in the site's former operations and for other remediation projects. In the first six months of 2003, the Company recorded a provision for the revised estimated costs of the impoundment closure plan based on the TCEQ initial draft permit that was issued for the site.

During the first six months of 2003, provisions of $9 million were recorded for the "Company facilities sold with retained liabilities and former Company-operated sites" category. These provisions included the estimated cleanup costs for oil fields located in Michigan and California that were formerly operated by the Company. The estimated costs are based on assessments recently performed at the sites. The provisions for this category of sites were also the result of revised remediation cost estimates that were identified during the first and second quarters of 2003 for former service station sites.

During the first six months of 2003, estimated possible additional costs in excess of amounts included in the reserves for remediation obligations decreased by $40 million. The decrease was primarily for sites in the "Active Company facilities" category, as a result of the reclassification of costs to asset retirement obligations under SFAS No. 143 for the Company's Molycorp subsidiary (see note 2 for further detail). The decrease was also the result of the Company lowering its estimated costs for the "Inactive or closed Company facilities" category of sites by $20 million. These costs were included in the amounts added to the reserve for the Guadalupe oil field and the Beaumont Refinery sites as discussed above.

Partially offsetting the foregoing decreases was an increase of $5 million in possible additional costs for the "Superfund and similar sites" category. The increase is based on preliminary information that the Company has received regarding possible payments for remediation-related work that may need to be made for two sites located in California. Estimated possible additional costs for the "Company facilities sold with retained liabilities and former Company-operated sites" category also increased by $5 million during the first six months of 2003. This increase was primarily for costs that may be incurred related to the cleanup of various sites that were part of the auto/truckstop system that the Company sold in 1993.

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OUTLOOK

Certain of the statements in this discussion, as well as other forward-looking statements within this document, contain estimates and projections of amounts of or increases/decreases in future revenues, earnings, cash flows, capital expenditures, assets, liabilities and other financial items and of future levels of or increases/decreases in reserves, production, sales including related costs and prices, drilling activities and other statistical items; plans and objectives of management regarding the Company's future operations, products and services; and certain assumptions underlying such estimates, projection plans and objectives. While these forward-looking statements are made in good faith, future operating, market, competitive, legal, economic, political, environmental, and other conditions and events could cause actual results to differ materially from those in the foward-looking statements. See pages 56 through 64 of Management's Discussion and Analysis in Item 7 of the Company's 2002 Annual Report on Form 10-K for a discussion of certain of such conditions and events.

The economic situation in Asia, where most of the Company's international activity is centered, is still recovering with positive signs showing in the region. The Company looks at the natural gas market in Asia as one of its major strategic investments and believes that the governments in the region are committed to undertaking the reforms and restructuring necessary to enable their nations to continue their recoveries from the downturn. Volatile energy prices are expected to continue to impact financial results. The Company expects energy prices to remain volatile due to changes in climate conditions, worldwide demand, crude oil and natural gas inventory levels, production quotas set by OPEC, current and future worldwide political instability, especially concerning Iraq and Nigeria, security and other factors.

The Company currently estimates its full-year 2003 production to average between 470,000 to 480,000 BOE per day. This production forecast includes the associated production loss of approximately 5,000 BOE per day from divestitures that the Company has completed so far this year. This estimate also reflects the sale of the Company's interest in Matador and a one-month delay in the start-up of the West Seno field in Indonesia. The Company has additional property divestitures pending or planned that if sold are expected to reduce production by 25,000 to 30,000 BOE per day. The Company's total actual production for the year could also be impacted by cost recovery volume fluctuations under the Company's various foreign PSCs due to changes in commodity prices, demand for natural gas in Thailand, the rate of ramp-up in West Seno production, and production and exploration performance in the Gulf of Mexico. For the remainder of 2003, the Company has hedged 49.5 million MMBtus of Lower 48 natural gas production and 2.8 million Bbl of Lower 48 crude oil, together representing approximately 40 percent of expected Lower 48 BOE production. The Company has fixed price sales for 26 milion MMBtu of natural gas at $5.94 per MMBtu and 1.2 million Bbl of crude oil at $30.08. In addition, the Company has hedged 23 million MMBtu of natural gas with pricing collars between $4.65 and $3.79 per MMBtu and 1.6 million Bbl of crude oil with collars between $31.85 and $27.38 per Bbl. Based on current prices, the Company's net earnings for the full-year are expected to change 14 cents per share for each $1 change in the Company's average worldwide realized price for crude oil and 7 cents per share for every 10-cent change in its average realized North America natural gas price, excluding the effect of hedging activities. The Company forecasts pre-tax dry hole costs of $155 million to $185 million and that pre-tax pension-related expenses will increase over 2002 by approximately $65 million to $70 million.

Exploration and Production - North America

U.S. Lower 48

The Company continues its deep shelf program in the Gulf of Mexico. Production at the Harvest deep shelf discovery on West Cameron Block 44 commenced in late June, adding to the two other deep shelf producing fields. The Company is currently drilling a prospect at High Island Block 37, which is adjacent to the Jalapeno discovery in High Island 36 made in 2002. The Company expects to drill as many as 10 more wells in the remaining months of 2003.

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In the Gulf of Mexico deepwater, the Company completed a successful appraisal well at the Champlain discovery located on Atwater Valley Block 63. The Company participated in the appraisal well, which earned it a 30 percent interest in the discovery by paying for 50 percent of the well costs. The Company and its co-venturers will be working on development options and are aiming to sanction the project by year-end. The Champlain prospect is important to the Company because of its proximity to the Mirage discovery, located on Mississippi Canyon Block 941, where it has a 25 percent non-operating working interest.

The Company plans to continue funding the development of the Mad Dog discovery in which the Company has a 15.6 percent non-operating working interest. The Company anticipates first production in late 2004 or early 2005, with gross expected production of 75 MBbl/d of liquids and 35 MMcf/d of natural gas in 2007. The Company also expects the co-venture integrated project team of the K-2 discovery to complete a development plan in 2003.

The Company continues to move forward with studies on development options for its Trident discovery in the deepwater Gulf of Mexico. The Company is in discussions with all the operators in the area about development scenarios and joint development planning. The Company is the operator of the discovery and has a 59.5 percent working interest in a seven-block area.

The Company is currently drilling a well on its St. Malo prospect in the Walker Ridge area, a deep Eocene test. The Company received a 32 percent working interest in the well by paying 27.5 percent of the well cost. The Company is solidifying the drilling schedule for the remainder of the year and expects to drill another two wells in the Gulf of Mexico deepwater in 2003.

The Company announced that it has initiated a divestiture program that will involve approximately 100 fields in the Gulf of Mexico shelf and onshore (see note 10 to the consolidated financial statements in Item 1 of this report).

On July 15, 2003, the Company's wholly owned affiliate, Chicago Carbon Company ("Chicago"), filed with the SEC, an amended Schedule 13D with respect to Chicago's 14.71% interest in Tom Brown, Inc. ("Tom Brown"). The filing was made to reflect that Chicago had given notice to Tom Brown, of its request that the 5,800,000 shares of common stock it holds in Tom Brown be registered under the shelf registration statement that Tom Brown had filed with the SEC. In the event that Tom Brown's shelf registration statement is amended to include all of the shares owned by Chicago and that statement is declared effective by the SEC, then Chicago would be in a position to sell its Tom Brown shares subject to the usual and customary shelf registration statement procedures and the requirements of the contractual registration rights with Tom Brown.

Alaska

The Ninilchik Unit development in the South Kenai Peninsula is progressing. First production from the Ninilchik Unit is also expected in the fourth quarter of 2003, with that early production going to the Kenai Gas Storage Facility for delivery to customers beginning in the first quarter of 2004. The Company has a 40 percent non-operating interest in the unit.

Exploration and Production - International

Far East

Thailand: Demand for natural gas from the Company's fields has been strong as a result of the ongoing reduced production from adjacent fields operated by other companies. The Company expects higher average liquids production, with the full-year effect of crude oil production from its Yala field. The Company has a 71 percent working interest in the Yala field (62 percent net of royalty). The Company's plans are geared towards exploring for additional oil and gas resources in the Gulf of Thailand and supporting the efforts of PTT Exploration and Production PLC in the development of the Arthit gas field in the gulf. The Company has a 16 percent working interest in the Arthit gas field.

Indonesia: The Company's Unocal Ganal, Ltd. ("Unocal Ganal"), subsidiary has made a significant gas-condensate and oil discovery on the deepwater Gehem prospect in the Ganal production-sharing contract area, 3.5 miles south of the Ranggas field offshore East Kalimantan, Indonesia. The Gehem-1 well encountered 617 feet of net gas and gas-condensate pay and 18 feet of net oil pay. The well was drilled in 5,981 feet of water to a total vertical depth of 15,241 feet. More than 400 feet of the net pay was in a stratigraphic interval that had not been penetrated during drilling in the nearby Ranggas field. The results of the Gehem-1 well indicate possibly significant oil and condensate accumulations in the deeper untested trend underlying the existing Gada, Gula, and Ranggas discoveries.

The Company's new production from the deepwater West Seno oil and gas field came on line in early August 2003. Gross daily production from the first phase of development is expected to reach about 35 MBOE to 40 MBOE by the end of 2003, increasing to a peak production level of approximately 60 MBbl/d of oil and 150 MMcf/d of natural gas (gross) in late 2005 with the second phase of development. Gross development costs for the first phase are expected to be approximately $500 million with an additional $240 million for the second phase (Unocal's net share is expected to be approximately $450 million and $215 million for the first and second phases, respectively). The Company and its co-venturer completed financing arrangements for a portion of the total costs through the Overseas Private Investment Corporation in late March 2003 through two loans. One loan is $300 million for the first phase, and the other loan is $50 million for the second phase. The loan associated with the second phase is still subject to a final construction contract being obtained.

The Company's Unocal Rapak, Ltd. ("Unocal Rapak"), subsidiary successfully completed drilling the Ranggas Selatan-1 appraisal well, extending the Ranggas field to the south on the Rapak production-sharing contract area. The Selatan-1 well was drilled to a true vertical depth of 10,243 feet, and penetrated 187 feet of net oil pay and 258 feet of net gas pay in several zones of high quality reservoir rock. The well was not planned to penetrate the deep reservoir that was encountered in the Gehem-1 well. The Selatan-1 well was drilled 1 mile south of the Ranggas-1 discovery well and 5.7 miles north of the Gehem-1 well. The Company is conducting conceptual engineering studies for the possible development of the Ranggas field. Extending the Ranggas oil and gas accumulations to the south is an important and positive appraisal step for the field. While the Company is still planning to have the Ranggas development project ready for government approval by early next year, the Gehem-1 results have implications for appraising the deeper oil potential at Ranggas and optimizing the development. The Company plans to move the Ranggas project along while assessing the deep potential and options for co-development with Gehem. Unocal Rapak is operator of the Rapak PSC area and holds an 80-percent working interest.

The Company will be drilling another deep well in the Sadewa field in the East Kalimantan PSC area to test for oil. The Sadewa discovery well was drilled in 2002 and found both natural gas and oil. The oil play found near the bottom of the well provided encouragement for deeper oil potential that could not be fully evaluated at the time. The Company holds a 50 percent working interest in the well.

China: The Company has worked with China National Offshore Oil Corporation, China New Star Petroleum Corporation, the Shanghai Municipality and the State Planning Commission to promote appraisal and development of natural gas resources in the Xihu Trough, off the coast of Shanghai, in the East China Sea. Unocal believes the area could contain significant amounts of recoverable natural gas. The Company is continuing its negotiations and is still expecting to sign PSCs in 2003 to explore and develop natural gas resources. The Company's working interest is expected to be 20 percent.

Other International

Azerbaijan: The Azerbaijan International Operating Company ("AIOC") consortium, in which the Company has a 10.28% working interest, is on track with its development of Phases I and II of the offshore Azeri field in the Azeri-Chirag-Gunashli structure in the Azerbaijan sector of the Caspian Sea. The project is under construction and on schedule with first oil from the Phase 1 Central Azeri platform expected early in 2005. A third phase is in early engineering and is expected to be approved in 2004. Gross production from the combined phases, plus the currently producing Early Oil Project in the Chirag Field, is forecasted to be over 1 MMBbl/d (gross) by 2009. This forecast is contingent upon the completion of the BTC pipeline project and the general political risks inherent to the region. The multi-country nature of this pipeline along with multinational participation in the consortium, in addition to expected project financing from international lending institutions like the IFC and EBRD and from several export credit agencies, should help to mitigate the political risk.

Bangladesh: Domestic natural gas sales in the country have expanded and the Company completed work on amending agreements to increase the Take-or-Pay volume for natural gas sold to Petrobangla, the state oil and gas company. The new agreement increased the Take-or-Pay volume of natural gas from 80 MMcf/d to 100 MMcf/d gross. The Company also continues to work with the government of Bangladesh and Petrobangla to develop additional reserves and export natural gas to markets in neighboring India. At July 31, 2003, the Company's business unit in Bangladesh had a gross receivable balance of approximately $23 million relating to invoices billed for natural gas and condensate sales to Petrobangla. Approximately $20 million of the outstanding balance represented past due amounts and accrued interest for invoices covering March through June 2003. Generally, invoices, when paid, have been paid in full. The Company is working with Petrobangla and the government of Bangladesh regarding the collection of the outstanding receivables.

The government of Bangladesh has also approved the development plan of the Moulavi Bazar natural gas field in northeast Bangladesh. The Company is awaiting the required approval from Petrobangla for the gas sales and purchase contracts.

Myanmar: In late July 2003, the President of the United States signed the Burmese Freedom and Democracy Act of 2003 ("the Act") and issued Executive Order 13310 expanding existing U.S. sanctions against Myanmar. While the Company continues to evaluate the effect of these actions by the United States Government, it appears that they will not have a material adverse effect on revenues the Company receives from its interests in Myanmar.

Midstream

Construction of the BTC pipeline is progressing with about 15 percent of the project completed. The pipeline project is planned to have a crude oil throughput capacity of 1 million Bbl/d. Completion of the pipeline is expected in late 2004 at an overall estimated cost of approximately $3 billion, and the pipeline is expected to be in operation in early 2005. The Company has an 8.9 percent interest and is one of eleven shareholders in the BTC pipeline project. The pipeline company anticipates financing up to 70 percent of the pipeline's cost. The Company expects to sign a bridge financing agreement in the near future whereby the Company, along with several other participants will provide short-term financing to the State Oil Company of the Azerbaijan Republic ("SOCAR") for purposes of funding SOCAR's share of BTC pipeline expenditures until proceeds from the project financing are disbursed. The Company's 14.24% share of this financing is anticipated to amount to less than $50 million with payback, including interest, expected in the first half of 2004.

The Kenai Kachemak Pipeline in Alaska, currently under construction, will transport natural gas from Ninilchik to Kenai, where it will tie into the existing gas grid serving south central Alaska. The Company expects the 32-mile pipeline to be in operation in the fourth quarter of 2003.

Geothermal and Power Operations

In the Philippines, the Company's wholly-owned subsidiary Philippine Geothermal, Inc. and two government-owned entities, the National Power Corporation, the Power Sector Assets and Liabilities Corporation and the Philippine Department of Energy signed a compromise settlement agreement covering the definitive terms of settlement in March 2003. The parties are now in the process of securing all necessary Philippine government and court approvals of the settlement.

The Company's Unocal North Sumatra Geothermal, Ltd. subsidiary has agreed to sell its rights and interest in the Sarulla geothermal project on the island of Sumatra, Indonesia to the Indonesian state electricity company. The anticipated sales price is $60 million. The transaction is expected to close in the third quarter of 2003, and the Company expects to record a gain on the transaction (see note 10 to the consolidated financial statements in Item 1 of this report).

FUTURE ACCOUNTING CHANGES

FASB Interpretation No. 46: Effective January 1, 2003, the Company adopted FASB Interpretation No. 46, "Consolidation of Variable Interest Entities." (see note 2 to the consolidated financial statements in Item 1 of this report). The effective date for the consolidation of entities existing prior to February 1, 2003 is July 1, 2003. The Company expects the adoption of the recognition (i.e., consolidation) requirements of the Interpretation to increase its consolidated long-term debt by approximately $78 million in the third quarter of 2003. This covers third-party debt of DSPL (see note 12 to the consolidated financial statements in Item 1 of this report). An additional $242 million related to a partnership interest in which the Company had a minority interest liability would have been required to be consolidated under this Interpretation had it not been paid in July (see note 18 to the consolidated financial statements in Item 1 of this report).

SFAS No. 149: In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." This Statement amends and clarifies accounting for derivative instruments including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. The Company does not expect the adoption of SFAS No. 149 to have a significant impact on its financial position or results of operations.

Consistent with SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," costs of acquiring oil and gas drilling rights have been classified as tangible assets in property, plant and equipment. The Company understands the staff of the SEC believes SFAS No. 19 does not provide guidance as to whether these assets should be classified as tangible or intangible and therefore believe SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," would require that drilling rights be classified as an intangible asset. The SEC has requested the FASB to address this perceived conflict within the related FASB statements. The resolution of this issue will have no impact on the Company's results of operations. If the FASB concurs with the SEC, it would result in additional disclosures and a balance sheet reclassification of these assets from Properties-net to Intangible Assets.

Other proposed accounting changes considered from time to time by the FASB, the SEC and the United States Congress could materially impact the Company's reported financial position and results of operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risk generally represents the risk that losses may occur in the values of financial instruments as a result of changes in interest rates, foreign currency exchange rates and commodity prices. As part of its overall risk management strategies, the Company uses derivative financial instruments to manage and reduce risks associated with these factors. The Company also trades hydrocarbon derivative instruments, such as futures contracts, swaps and options to exploit anticipated opportunities arising from commodity price fluctuations.

The Company determines the fair values of its derivative financial instruments primarily based upon market quotes of exchange traded instruments. Most futures and options contracts are valued based upon direct exchange quotes or industry published price indices. Some instruments with longer maturity periods require financial modeling to accommodate calculations beyond the horizons of available exchange quotes. These models calculate values for outer periods using current exchange quotes (i.e., forward curve) and assumptions regarding interest rates, commodity and interest rate volatility and, in some cases, foreign currency exchange rates. While the Company feels that current exchange quotes and assumptions regarding interest rates and volatilities are appropriate factors to measure the fair value of its longer termed derivative instruments, other pricing assumptions or methodologies may lead to materially different results in some instances.

Interest Rate Risk - From time to time the Company temporarily invests its excess cash in short-term interest-bearing securities issued by high-quality issuers. Company policies limit the amount of investment in securities of any one financial institution. Due to the short time the investments are outstanding and their general liquidity, these instruments are classified as cash equivalents in the consolidated balance sheet and do not represent a material interest rate risk to the Company. The Company's primary market risk exposure to changes in interest rates relates to the Company's long-term debt obligations. The Company manages its exposure to changing interest rates principally through the use of a combination of fixed and floating rate debt. Interest rate risk sensitive derivative financial instruments, such as swaps or options may also be used depending upon market conditions.

The Company evaluated the potential effect that near term changes in interest rates would have had on the fair value of its interest rate risk sensitive financial instruments at June 30, 2003. Assuming a ten percent decrease in the Company's weighted average borrowing costs at June 30, 2003, the potential increase in the fair value of the Company's debt obligations and associated interest rate derivative instruments, including the debt obligations and associated interest rate derivative instruments of its subsidiaries, would have been approximately $95 million at June 30, 2003.

Foreign Exchange Rate Risk - The Company conducts business in various parts of the world and in various foreign currencies. To limit the Company's foreign currency exchange rate risk related to operating income, foreign sales agreements generally contain price provisions designed to insulate the Company's sales revenues against adverse foreign currency exchange rates. In most countries, energy products are valued and sold in U.S. dollars and foreign currency operating cost exposures have not been significant. In other countries, the Company is paid for product deliveries in local currencies but at prices indexed to the U.S. dollar. These funds, less amounts retained for operating costs, are converted to U.S. dollars as soon as practicable. The Company's Canadian subsidiaries are paid in Canadian dollars for their crude oil and natural gas sales.

From time to time the Company may purchase foreign currency options or enter into foreign currency swap or foreign currency forward contracts to limit the exposure related to its foreign currency debt or other obligations. At June 30, 2003, the Company had various foreign currency swaps and foreign currency forward contracts outstanding related to operations in Thailand and The Netherlands. The Company evaluated the effect that near term changes in foreign exchange rates would have had on the fair value of the Company's combined foreign currency position related to its outstanding foreign currency swaps and forward contracts. Assuming an adverse change of ten percent in foreign exchange rates at June 30, 2003, the potential decrease in fair value of the Company's foreign currency forward contracts, foreign-currency denominated debt, foreign currency swaps and foreign currency forward contracts of its subsidiaries, would have been approximately $28 million at June 30, 2003.

Commodity Price Risk - The Company is a producer, purchaser, marketer and trader of certain hydrocarbon commodities such as crude oil and condensate, natural gas and refined products and is subject to the associated price risks. The Company uses hydrocarbon price-sensitive derivative instruments ("hydrocarbon derivatives"), such as futures contracts, swaps, collars and options to mitigate its overall exposure to fluctuations in hydrocarbon commodity prices. The Company may also enter into hydrocarbon derivatives to hedge contractual delivery commitments and future crude oil and natural gas production against price exposure. The Company also actively trades hydrocarbon derivatives, primarily exchange regulated futures and options contracts, subject to internal policy limitations.

The Company uses a variance-covariance value at risk model to assess the market risk of its hydrocarbon derivatives. Value at risk represents the potential loss in fair value the Company would experience on its hydrocarbon derivatives, using calculated volatilities and correlations over a specified time period with a given confidence level. The Company's risk model is based upon current market data and uses a three-day time interval with a 97.5 percent confidence level. The model includes offsetting physical positions for any existing hydrocarbon derivatives related to the Company's fixed price pre-paid crude oil and pre-paid natural gas sales. The model also includes the Company's net interests in its subsidiaries' crude oil and natural gas hydrocarbon derivatives and forward sales contracts. Based upon the Company's risk model, the value at risk related to hydrocarbon derivatives held for hedging purposes was approximately $17 million at June 30, 2003. The value at risk related to hydrocarbon derivatives held for non-hedging purposes was approximately $1 million at June 30, 2003.

In order to provide a more comprehensive view of the Company's commodity price risk, a tabular presentation of open hydrocarbon derivatives is also provided. The following table sets forth the future volumes and price ranges of hydrocarbon derivatives held by the Company at June 30, 2003, along with the fair values of those instruments.

Open Hydrocarbon Hedging Derivative Instruments (a)

	2003	2004	2005	2006

Natural Gas Futures Positions				
Volume (MMBtu)	(13,960,000)	(9,850,000)	-	
Average price, per MMBtu	$ 5.92	$ 6.06		
Natural Gas Swap Positions				
Pay fixed price				
Volume (MMBtu)	8,368,500	14,726,500	7,893,000	7,218,
Average swap price, per MMBtu	$ 4.46	$ 4.02	$ 2.59	$ 2
Receive fixed price				
Volume (MMBtu)	8,240,000	11,830,000	-	
Average swap price, per MMBtu	$ 6.12	$ 6.14		
Natural Gas Basis Swap Positions				
Volume (MMBtu)	19,650,000	-	-	
Average price received, per MMBtu	$ 5.20			
Average price paid, per MMBtu	$ 4.61			
Natural Gas Collar Positions				
Volume (MMBtu)	23,811,000	268,500	-	
Average ceiling price, per MMBtu	$ 4.64	$ 5.45		
Average floor price, per MMBtu	$ 3.79	$ 2.82		
Natural Gas Option (OTC)				
Put Volume (MMBtu)	(12,300,000)	-	-	
Average Put Price	$ 3.25			
Crude Oil Future position				
Volume (Bbls)	(760,000)	-	-	
Average price, per Bbl	$ 29.54			
Crude Oil Option				
Put Volume (Bbls)	-	-	-	
Average price, per Bbl	$ -			
Call Volume (Bbls)	-	-	-	
Average price, per Bbl	$ -			
Crude Oil Option (OTC)				
Put Volume (Bbls)	(1,200,000)	(720,000)	-	
Average price, per Bbl	$ 24.00	$ 20.00		
Crude Oil Collar Positions				
Volume (Bbls)	1,277,500	810,000	-	
Average ceiling price, per Bbl	$ 32.25	$ 28.16		
Average floor price, per Bbl	$ 27.43	$ 23.41		

Open Hydrocarbon Non-Hedging Derivative Instruments (a)

2003

Natural Gas Futures Positions	
Volume (MMBtu)	8,700,000
Average price, per MMBtu	$ 5.73
Natural Gas Swap Positions	
Pay fixed price	
Volume (MMBtu)	7,030,000
Average swap price, per MMBtu	$ 5.77
Receive fixed price	
Volume (MMBtu)	7,894,748
Average swap price, per MMBtu	$ 5.61
Natural Gas Basis Swap Positions	
Volume (MMBtu)	-
Average price received, per MMBtu	$-
Average price paid, per MMBtu	$-
Natural Gas Spread Swap Positions	
Volume (MMBtu)	4,429,999
Average price received, per MMBtu	$ 0.70
Average price paid, per MMBtu	$ 0.54
Natural Gas Option (Listed)	
Call Volume (MMBtu)	(29,380,000)
Average Call price	$ 6.42
Put Volume (MMBtu)	8,150,000
Average Put Price	$ 5.27
Natural Gas Option (Over the Counter)	
Call Volume (MMBtu)	(2,236,150)
Average Call price	$ 3.85
Put Volume (MMBtu)	(4,620,000)
Average Put price	$ 4.26
Natural Gas Spread Option (Over the Counter)	
NYMEX / IFERC (c)	
Call Volume (MMBtu)	(810,000)
Average Strike price	$ 1.14
Put Volume (MMBtu)	(3,000,000)
Average Strike price	$ 0.25
Crude Oil Future position	
Volume (Bbls)	-
Average price, per Bbl	$-
Crude Oil Option	
Put Volume (Bbls)	-
Average price, per Bbl	$ -
Call Volumes (Bbls)	200,000
Average price, per Bbl	$ 32.50
Crude Oil Swap Positions	
Pay fixed price	
Volume (Bbls)	2,732,500
Average swap price, per Bbl	$ 27.85
Receive fixed price	
Volume (Bbls)	2,650,000
Average swap price, per Bbl	$ 27.57

ITEM 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, the Company carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-15(e) of the Securities Exchange Act of 1934. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective in timely identifying material information potentially required to be included in the Company's SEC filings.

There was no change in the Company's internal control over financial reporting that occurred during the second quarter of 2003 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Section 404 of the Sarbanes-Oxley Act of 2002 will require the Company to include an internal control report with its 2004 annual report on Form 10-K. The internal control report must assert (i) management's responsibilities to establish and maintain adequate internal control over financial reporting and (ii) management's assessment of the effectiveness of this internal control as of the end of the most recent fiscal year. The Company's auditors will, in 2004, be required to attest to, and report on, these assertions. In order to achieve compliance with Section 404 within the statutory period, management has formed a steering committee and adopted a detailed project work plan to assess the adequacy of the Company's internal controls, remediate any control weaknesses that may be identified, validate through testing that controls are functioning as documented. As a result of this initiative, the Company may make changes in its internal controls from time to time during the period prior to December 31, 2004.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

See the information with respect to certain legal proceedings pending or threatened against the Company previously reported in Item 3 of Unocal's Annual Report on Form 10-K for the year ended December 31, 2002, and in Item 1 of Part II of Unocal's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2003. There is incorporated by reference: the information regarding the environmental remediation reserve and possible additional remediation costs in notes 13 and 14 to the consolidated financial statements in Item 1 of Part I of this report; the discussion of such amounts in the Environmental Matters section of Management's Discussion and Analysis in Item 2 of Part I; and the information regarding certain litigation and claims, tax matters and other contingent liabilities in note 14 to the consolidated financial statements.

Information with respect to recent developments in certain previously reported proceedings is set forth below:

1. In the federal cases (the Doe and Roe cases) alleging the Company's liability in connection with the construction of the natural gas pipeline

from the Yadana field across Myanmar to the Thailand border, described in Paragraph 2 of Item 3 of the 2002 Form 10-K, a rehearing took place in June 2003 before an eleven-judge "en banc" panel of the U.S. Court of Appeals for the Ninth Circuit of the appellate court decision remanding the cases for further proceedings in the District Court. A decision is not expected for several months.

In the California Superior Court cases, the court has bifurcated the trial. Phase I will address whether the correct defendants are before the court. If Unocal is unsuccessful in Phase I, then Phase II will address liability and damages. Phase I is currently scheduled for September 2003 and Phase II for December 2003.

The Company believes that the outcomes of the federal and state cases are not likely to have a material adverse effect on the Company's financial condition or liquidity or, based on management's current assessment of the cases, the Company's results of operations.

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ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

The 2003 Annual Meeting of Stockholders of Unocal was held on May 19, 2003. The following actions were taken by the stockholders at the Annual Meeting, for which proxies were solicited pursuant to Regulation 14 under the Securities Exchange Act of 1934, as amended:

1. The four nominees proposed by the board of directors were elected as directors by the following votes for three-year terms expiring at the 2006 Annual Meeting of Stockholders, or until their successors are duly elected and qualified:

Name	Votes For	Votes Withheld
John W. Amerman	218,336,231	8,195,535
John W. Creighton, Jr.	218,441,184	8,093,582
Ferrell P. McClean	218,714,080	7,820,686
Kevin W. Sharer	219,524,450	7,010,316

2. A proposal to ratify the appointment of PricewaterhouseCoopers LLP as Unocal's independent accountants for 2003 was passed by a vote of 217,480,891 for versus 7,556,964 against and 1,492,890 abstentions. There were 4,022 broker non-votes.

3. A stockholder proposal to urge the Board of Directors to take the necessary steps to amend the bylaws to require that an independent director who has not served as chief executive officer of the Company to serve as chairman of the Board of Directors failed to pass, with a vote of 20,361,699 for versus 175,106,931 against and 2,281,969 abstentions. There were 28,784,168 broker non-votes.

4. A stockholder proposal to request the Board of Directors to take the needed steps to hire an investment banking firm to sell the Company failed to pass, with a vote of 7,827,942 for versus 187,072,700 against and 2,849,956 abstentions. There were 28,784,169 broker non-votes.

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

(a) Exhibits: The Exhibit Index on page 57 of this report lists the exhibits that are filed as part of this report.

(b) Reports on Form 8-K:

Filed during the second quarter of 2003:

(1) Current Report on Form 8-K, dated April 1, 2003, and filed April 2, 2003, for the purpose of reporting, under Item 5 and Item 7, an amendment to Unocal's Rights Agreement.

(2) Current Report on Form 8-K, dated April 24, 2003, and filed April 28, 2003, for the purpose of reporting, under Item 5, the Company's first quarter 2003 earnings and related information and the Company's 2003 outlook.

(3) Current Report on Form 8-K, dated and filed June 5, 2003, for the purpose of reporting, under Item 5, the Company's intent to sell assets in the U.S. Gulf of Mexico and other business related news.

(4) Current Report on Form 8-K, dated and filed June 27, 2003, for the purpose of reporting, under Item 5 and Item 7, the Company's acquisition of the outstanding limited partner interest in a consolidated limited partnership.

Filed during the third quarter of 2003 to the date hereof:

(1) Current Report on Form 8-K, dated and filed July 14, 2003, for the purpose of reporting, under Item 5, the Company's agreement to sell its rights and interest in the Sarulla geothermal project on the island of Sumatra in Indonesia.

(2) Current Report on Form 8-K, dated July 15, 2003, and filed July 16, 2003, for the purpose of reporting, under Item 5 and Item 7, the Company's filing of an amended Schedule 13D with respect to the Company's interest in Tom Brown, Inc.

(3) Current Report on Form 8-K, dated July 23, 2003, and filed July 24, 2003, for the purpose of reporting, under Item 5, the Company's discovery on the deepwater Gehem prospect, offshore East Kalimantan, Indonesia.

(4) Current Report on Form 8-K, dated July 29, 2003, and filed July 31, 2003, for the purpose of reporting, under Item 5, the Company's second quarter and six months earnings results, other related information and the Company's 2003 outlook.

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.

UNOCAL CORPORATION
(Registrant)

Dated: August 11, 2003

By: /s/ JOE D. CECIL

Joe D. Cecil
Vice President and Comptroller
(Duly Authorized Officer and
Principal Accounting Officer)

EXHIBIT INDEX

10 Employment Agreement, effective as of March 12, 2003, by and between Unocal and Thomas E. Fisher.

12.1 Statement regarding computation of ratio of earnings to fixed charges of Unocal Corporation for the six months ended June 30, 2003 and 2002.

12.2 Statement regarding computation of ratio of earnings to fixed charges of Union Oil Company of California for the six months ended June 30, 2003 and 2002.

31 Certifications Pursuant to 18 U.S.C Section 1350, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32 Certifications Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Copies of exhibits will be furnished upon request. Requests should be addressed to the Corporate Secretary.