UNOCAL CORP
Form 10-Q
August 04, 2005

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

FORM 10-Q

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

For the quarterly period ended June 30, 2005

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 Exchange Act). Yes X No _______

Number of shares of common stock, $1.00 par value, outstanding as of July 29, 2005: 273,631,943

UNOCAL CORPORATION

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GLOSSARY

Below are definitions of certain common industry terms that may be used in this Form 10-Q:

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		

o 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 crude oil.

- Bilateral institution refers to a country specific institution that 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 crude oil and natural gas amounts using a standard measurement. Natural gas volumes are converted to barrels of oil equivalent on the basis of 6,000 cubic feet of natural 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 natural gas 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 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 our share of the cost recovery revenue and the profit revenue is divided by market oil and gas prices and represents the volume to which we are entitled. 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 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 agrees to pay a portion of past or future costs. 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 field. Produced fluids are brought by flowlines to the vessel where they are separated, or treated, or stored and then offloaded to another vessel or pipeline for transportation.

- Gross acres or gross wells are the total acres or wells in which we have a working interest.

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

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

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

- 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.

- 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").

- 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.

- Net acreage and net oil and gas wells are obtained by multiplying gross acreage and gross oil and gas wells by our working interest percentage in the properties.

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

- Net working interest is a working interest after deducting royalties and other economic interests payable to third parties. Our net working interest may vary over time due to changes in commodity prices, costs and other factors.

- OPEC is the abbreviation for Organization of Petroleum Exporting Countries.

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

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

- 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 crude oil and natural gas.

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

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

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

- 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. In some contracts, the purchaser has the right in following years to take product that had been paid for but not taken.

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

- Working Interest ("WI") is the percentage of ownership we have in a joint venture, partnership, consortium, project or acreage. Our working interest does not necessarily equal our share of revenues or production. See "Net working interest" definition above.

- West Texas Intermediate ("WTI") crude oil is a light, sweet crude oil (high API gravity, low sulfur) used as the benchmark for U.S. crude oil refining and trading. WTI is deliverable at Cushing, Oklahoma to fill New York Mercantile Exchange ("NYMEX") futures contracts for light, sweet crude oil.

For the purpose of this report, the terms "Unocal," "Union Oil," "we," "our," "its" and the "Company" refer to Unocal Corporation ("Unocal") and its consolidated subsidiaries, including Union Oil Company of California ("Union Oil"), unless the context otherwise provides.

FORWARD-LOOKING STATEMENTS

This cautionary note is provided pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 and Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are included in this report and may be included in other public filings, press releases, our website and oral and written presentations by management. Statements other than historical facts are forward-looking and may be identified by words such as "expects," "anticipates," "intends," "plans," "believes," "estimates," "forecasts," "could," "will" and words of similar meaning. Examples of these types of statements include those regarding:

- our pending merger with Chevron Corporation ("Chevron"),
- the pending sale of our Canadian exploration and production business to Pogo Producing Company ("Pogo"),
- assessments of hydrocarbon formations and potential resources,
- exploration, development and other plans for future operations,
- production rates, timing and costs and sales volumes and prices,
- revenues, earnings, cash flows, liabilities, capital expenditures and other financial measures,
- anticipated liquidity,
- the amount and timing of environmental and other contingent liabilities, and
- other statements regarding future events, conditions or outcomes.

Although these statements are based upon our current expectations and beliefs, they are subject to known and unknown risks and uncertainties that could cause actual results and outcomes to differ materially from those described in, or implied by, the forward-looking statements. In that event, our business, financial condition, results of operations or liquidity could be materially adversely affected and investors in our securities could lose part or all of their investments. These risks and uncertainties include, for example:

- approval by our stockholders of the Chevron merger and the effects on us in the event that the Chevron merger is not completed,

- satisfaction of the conditions to completing the sale of our Canadian exploration and production business to Pogo,
- volatility in commodity prices,
- our ability to find or acquire commercially productive reservoirs and to develop and produce deepwater and other projects in a timely and cost-effective manner,
- the accuracy of our estimates and judgments regarding hydrocarbon resources and formations and reservoir performance,
- operational risks inherent in the exploration, development and production of oil and gas,
- the impact of environmental laws, permitting and licensing requirements and other regulations,
- international and domestic political and economic factors, and
- other factors discussed in our Risk Factors section in Part II, Item 7 of our 2004 Annual Report on Form 10-K.

Copies of our SEC filings are available by calling us at (800) 252-2233 or from the SEC by calling (800) SEC-0330. The reports are also available on our web site, www.unocal.com. We undertake no obligation to update the forward-looking statements in this report or in other documents, our website or oral statements to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONSOLIDATED EARNINGS (UNAUDITED)

	For the Three Months Ended June 30,	
Millions of dollars except per share amounts	2005	20
Revenues		
Sales and operating revenues (a) (see note 3)	$ 2,161	$ 1,7
Interest, dividends and miscellaneous income	42	
Gain on sales of assets (see note 4)	10	
Total revenues	2,213	1,8
Costs and other deductions		
Crude oil, natural gas and product purchases (a)	748	7
Operating expense	323	3
Administrative and general expense	66	
Depreciation, depletion and amortization	269	2
Impairments	1	
Dry hole costs	12	
Exploration expense (see note 3)	36	
Interest expense (see note 3)	32	
Property and other operating taxes	29	
Total costs and other deductions	1,516	1,4
Earnings from equity investments	18	
Earnings from continuing operations before income taxes and minority interests	715	4

Income taxes	273	1
Minority interests	2	
Earnings from continuing operations	440	2
Earnings from discontinued operations (b) (see note 6)	35	
Net earnings	$ 475	$ 3
Basic earnings per share of common stock (c)		
Continuing operations	$ 1.62	$ 1.
Discontinued operations	0.13	0.
Net earnings	$ 1.75	$ 1.
Diluted earnings per share of common stock (d)		
Continuing operations	$ 1.60	$ 0.
Discontinued operations	0.13	0.
Net earnings	$ 1.73	$ 1.
Cash dividends declared per share of common stock	$ 0.20	$ 0.

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CONSOLIDATED BALANCE SHEETS UNOCA

	At June 30,	At
Millions of dollars	2005 (a)	
Assets		
Current assets		
Cash and cash equivalents (see note 10)	$ 1,775	
Accounts and notes receivable - net (see note 3)	1,267	
Inventories (see note 3)	165	
Deferred income taxes	76	
Assets held for sale (see note 11)	1,372	
Other current assets	43	
Total current assets	4,698	
Investments and long-term receivables - net (see note 3)	720	
Properties - net (see note 3)	7,806	
Goodwill	81	
Deferred income taxes	266	
Other assets	198	
Total assets	$ 13,769	
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 1,149	
Taxes payable	323	
Dividends payable	54	
Interest payable	35	
Current portion of environmental liabilities (see note 16)	112	

Current portion of long-term debt and capital leases (see note 14)	464
Liabilities of assets held for sale (see note 11)	411
Other current liabilities	208
Total current liabilities	2,756
Long-term debt and capital leases (see note 14)	2,076
Deferred income taxes	591
Accrued abandonment, restoration and environmental liabilities (see note 16)	866
Other deferred credits and liabilities	1,093
Minority interests	29
Commitments and contingencies - (see note 17)	
Common stock ($1 par value, shares authorized: 750,000,000 (b))	289
Capital in excess of par value	1,685
Unearned portion of restricted stock issued	(35)
Retained earnings	5,273
Accumulated other comprehensive income	(217)
Notes receivable - key employees	(3)
Treasury stock - at cost (c)	(634)
Total stockholders' equity	6,358
Total liabilities and stockholders' equity	$ 13,769

CONSOLIDATED CASH FLOWS (UNAUDITED)

	F
Millions of dollars	20
Cash Flows from Operating Activities	
Net earnings	$ 9
Adjustments to reconcile net earnings to net cash provided by operating activities	
Depreciation, depletion and amortization	5
Impairments	
Dry hole costs	
Amortization of exploratory leasehold costs	
Deferred income taxes	1
Gain on sales of assets	(
Gain on disposal of discontinued operations	(
Pension expense net of contributions	
Other	(
Working capital and other changes related to operations	
Accounts and notes receivable	
Inventories	
Accounts payable	(
Taxes payable	(
Other	
Net cash provided by operating activities	1,6

Cash Flows from Investing Activities	
Capital expenditures (includes dry hole costs)	(8
Proceeds from sales of assets	1
Proceeds from sales of discontinued operations	
Return of capital from affiliate company	
Net cash used in investing activities	(7
Cash Flows from Financing Activities	
Long-term borrowings	
Reduction of long-term debt and capital lease obligations	(2
Minority interests	
Repurchases of common stock	
Proceeds from issuance of common stock	1
Dividends paid on common stock	(1
Loans to key employees	
Other	
Net cash used in financing activities	(2
Total increase in cash and cash equivalents	6
Less: Cash and cash equivalents of assets held for sale	
Cash and cash equivalents at beginning of year	1,1
Cash and cash equivalents at end of period	$ 1,7
Supplemental disclosure of cash flow information:	
Cash paid during the period for:	
Interest (net of amount capitalized)	$
Income taxes (net of refunds)	$ 4

See Notes to the Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. General

The consolidated financial statements included in this report are unaudited and, in the opinion of our management, include all adjustments necessary for a fair statement of our financial position and results of operations. All adjustments are of a normal recurring nature.

Certain notes and other information have been condensed or omitted from these interim financial statements in accordance with the Securities and Exchange Commission ("SEC") disclosure requirements for Form 10-Q. Therefore, these interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the related notes filed with the SEC in our 2004 Annual Report on Form 10-K ("2004 10-K").

Our consolidated financial statements include the accounts of subsidiaries in which a controlling interest is held and variable interest entities where Unocal is the primary beneficiary. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis.

Investments in entities without a controlling interest are accounted for by the equity method or cost basis. Under the equity method, our investments are stated at cost plus the equity in undistributed earnings and losses after acquisition. Income taxes estimated to be payable when earnings are distributed are included in deferred income taxes. Other securities and investments excluding marketable securities are generally carried at cost. Under the cost method, the investments are recorded at cost, and we recognize as income dividends received that are distributed from net accumulated earnings of the investee since the date of acquisition.

We follow the successful efforts method of accounting for our oil and gas activities.

Results for the six months ended June 30, 2005, are not necessarily indicative of future financial results.

The financial statements of the prior periods have been reclassified to conform to the 2005 presentation. We classified as discontinued operations our needle coke and Western Canada exploration and production businesses and reclassified all prior periods accordingly. See notes 6, 11 and 21 for further detail.

2. Accounting Changes and New Accounting Pronouncements

Emerging Issues Task Force ("EITF") Issue 04-9 and Financial Accounting Standards Board ("FASB") Staff Position ("FSP") FAS 19-1: Statement of Financial Accounting Standards ("SFAS") No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" requires the cost of drilling an exploratory well to be capitalized pending determination of whether the well has found proved reserves. If this determination cannot be made at the conclusion of drilling, SFAS No. 19 sets out additional requirements for continuing to carry the cost of the well as an asset. These requirements include firm plans for further drilling and a one-year time limitation on continued capitalization in certain instances. The EITF in their discussions of this issue noted that as a result of the increasing complexity of oil and gas projects due to drilling in remote and deepwater offshore locations, companies increasingly require more than one year to complete all of the activities that permit recognition of proved reserves. Furthermore, because of new technologies, additional exploratory wells may no longer be required before a project can commence. EITF Issue 04-9, "Accounting for Suspended Well Costs," sought to determine whether SFAS No. 19 should be clarified to recognize the industry changes that have taken place in the past quarter century. This issue was discussed by the EITF and it was determined that a formal amendment to SFAS No. 19 would be required if the FASB concurs with broadening the requirements for continued capitalization of exploratory well costs. In April 2005, the FASB issued FSP FAS 19-1, which we adopted effective January 1, 2005. This FSP amends SFAS No. 19 to allow continued capitalization when (a) the well has found a sufficient quantity of reserves to justify proceeding with the project plan and (b) the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project which may include more than one exploratory well if the reserves are intended to be extracted in a single integrated operation. The FSP also requires increased disclosures, which are presented in note 12. Adoption of this rule did not impact our consolidated earnings in the first six months of 2005. If this FSP had been applied to 2004, it would not have had a material effect on our earnings for that year.

American Jobs Creation Act: The American Jobs Creation Act of 2004 (the "Act") was signed into law by the U.S. President on October 22, 2004. The Act contains numerous changes to U.S. tax law, both temporary and permanent in nature, including a potential tax deduction with respect to certain qualified domestic manufacturing activities, which will be phased in from 2005 through 2010. Under the guidance in FSP FAS 109-1, "Application of FASB Statement No. 109, "Accounting for Income Taxes," to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004," the deduction will be reported in the period in which the deduction is claimed on our tax return. Based on current earnings levels, we estimate the increase in net earnings generated by this deduction will be in the range of zero to $15 million in both calendar years 2005 and 2006 and in the range of zero to $20 million per year by the end of the phase-in period in 2010.

The Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85 percent dividends received deduction for certain dividends from controlled foreign corporations. Because we incur a foreign tax rate in excess of the 35 percent U.S. federal income tax rate, we do not pay incremental federal income tax on our foreign earnings due to excess foreign tax credits. Therefore, we do not anticipate repatriating higher amounts of foreign earnings under the Act since any such repatriations would not reduce federal income taxes. In addition, this Act includes changes in the carryback and carryforward utilization periods for foreign tax credits.

SFAS No. 151: In 2004, the FASB issued SFAS No. 151, "Inventory Costs - an amendment of ARB No. 43, Chapter 4," which is effective for inventory costs incurred after December 31, 2005. This statement requires that items such as idle facility expense, excessive spoilage, double freight, and rehandling costs be recognized as current-period charges regardless of whether they meet the criterion of "so abnormal" as provided in Chapter 4 of ARB No. 43. In addition, this statement requires that fixed production overhead allocated to inventory be based on the normal capacity of the production facilities. Adoption of this pronouncement is not expected to have a significant impact on either our earnings or consolidated balance sheet.

SFAS No. 123 (revised 2004): In 2004, the FASB issued SFAS No. 123 (revised 2004) "Share-Based Payment," an amendment of FASB Statement Nos. 123 and 95, which is effective January 1, 2006. This pronouncement requires the fair value method to account for share-based awards and potentially increases the number of grants considered liability awards. In addition to more disclosures and a change in reporting the cash flows of certain stock option excess realized income tax benefits, it also requires liability awards to be reported at fair value rather than intrinsic value. Equity awards will continue to be recorded at grant-date fair value and recognized over the vesting period. Liability awards will be reported at fair value until settlement or expiration. Because we commenced in 2003 to prospectively expense new stock option grants, this standard is not expected to have a material impact on either our earnings or consolidated balance sheet.

SFAS No. 153: In 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29," which is effective July 1, 2005. With certain exceptions, this requires exchanges of nonmonetary assets to be recorded at fair value. Previously, these transactions were generally recorded at book value. This pronouncement results in reporting in earnings, gains and losses on exchanges of nonmonetary assets. Adoption of this rule is not expected to have a material impact on either our earnings or consolidated balance sheet.

SFAS No. 154: In 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and SFAS No. 3," which is effective January 1, 2006. Opinion 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. This Statement requires retrospective application (restatement) to prior periods' financial statements of changes in accounting principle. This Statement also applies to changes required by a new accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions.

EITF Issue No. 04-13: In 2004, the EITF initiated a review under Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same

Counterparty," to determine if they should be reported on a gross basis or a net basis. For many years, we have used a type of transaction commonly called a buy/sell, which generally consists of the purchase and sale of crude oil from the same counterparty. In a typical buy/sell transaction, Company A enters into a contract to sell a particular grade of crude oil at a specified location to Company B on a future date, and simultaneously agrees to buy from Company B a particular grade of crude oil at a different location at the same or another specified date.

The characteristics of buy/sell transactions include gross invoicing reflecting the quality and location differences of the crude oil, physical delivery requirements and separate payment terms. Nonperformance by one party does not relieve the other party's obligation to perform under the contract except for events of force majeure. The risks and rewards of ownership are evidenced by title transfer, assumption of environmental risk, transportation scheduling and counterparty credit risk. Because of these characteristics, we, as well as many of our industry peers, report the sale of the barrels as gross revenues and the purchase of the barrels as gross purchases in accordance with EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent." These characteristics also provide evidence that these transactions are monetary in nature and thus outside the scope of APB Opinion No. 29.

We understand that some registrants in our industry may report buy/sell transactions using a net rather than a gross presentation. The EITF is reviewing these transactions to determine if more specific guidance is needed for determining whether a net rather than a gross presentation in consolidated earnings is appropriate. While a net presentation of this issue would reduce both our revenues and our purchases, our net earnings would not be affected.

FASB Interpretation No. 47: In March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143," which is effective no later than December 31, 2005. This pronouncement clarifies that the term "conditional asset retirement obligation" as used in FASB Statement 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform an asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. When sufficient information exists, uncertainty about the timing and (or) method of settlement should be factored into the measurement of the liability. This interpretation is not expected to have a material impact on either our earnings or consolidated balance sheet.

3. Other Financial Information

o Revenues - Sales and operating revenues from marketing activities were $935 million in the second quarter of 2005, compared with $851 million in the same period a year ago. During the second quarters of 2005 and 2004, 21 percent and 28 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from outside parties by our Midstream and Marketing segment. For the six months ended June 30, 2005 and 2004, sales and operating revenues from marketing activities were $1.83 billion compared with $1.68 billion and the percentages attributable to resale activities were approximately 22 percent and 29 percent, respectively. The percentages in both the quarterly and yearly periods included crude oil buy/sell transactions. Crude oil buy/sell amounts were primarily lower in 2005 due to a significant decrease in volumes associated with these transactions, which was partially offset by higher crude oil prices for the periods shown (see crude oil buy/sell discussions in Item 8 of our 2004 10-K in the consolidated financial statements under notes 1 and 2). These marketing activities allowed us to better manage commodity-related risk by effectively transferring commodities from production locations to industry marketing centers with higher volumes of commercial activity and greater market liquidity.

o Exploration expense - Our 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	2005	2004	2005	2004
Exploration operations	$ 16	$ 18	$ 29	$ 34
Geological and geophysical	12	9	20	24
Amortization of exploratory leasehold costs	4	11	12	22
Leasehold rentals	4	3	5	5
Exploration expense	$ 36	$ 41	$ 66	$ 85

The six month period of 2005 compared to the same period a year ago reflects lower exploration expenditures of $12 million in the United States, primarily from lower activity in the Gulf of Mexico and $7 million from International operations.

o Capitalized interest - During the second quarters of 2005 and 2004, capitalized interest totaled $14 million and $10 million, respectively. For the six months ended June 30, 2005 and 2004, capitalized interest totaled $29 million and $26 million, respectively.

o Accounts and notes receivable - The allowance for doubtful accounts and notes receivable was $4 million and $5 million at June 30, 2005 and December 31, 2004, respectively.

o Inventories - At June 30, 2005, inventories were $165 million, which was a decrease of $55 million from year-end 2004 reflecting seasonal natural gas withdrawals in our Canadian natural gas storage business, which is included in our Midstream and Marketing segment. The decrease also reflected $5 million which was reclassified to assets held for sale (see note 11).

o Investments and long-term receivables - The allowances for investments and long-term receivables were $13 million and $32 million at June 30, 2005 and December 31, 2004, respectively. The decrease in the allowances for the current year reflects the disposal of our investment interest in two foreign equity investees.

o Properties - Accumulated depreciation, depletion and amortization was $12,144 million and $12,597 million at June 30, 2005 and December 31, 2004, respectively. The current year amount excludes $899 million of accumulated depreciation, depletion and amortization included in the assets held for sale amount on the face of the consolidated balance sheet (see note 11).

4. Dispositions Of Assets

Certain of our 2005 asset sales are discussed below:

In April, 2005, we sold our needle coke business for $25 million in cash plus $22 million in net working capital. We recorded an after-tax gain of $12 million.

In March 2005, our Molycorp subsidiary sold down its equity investment in Companhia Brasileira de Metalurgia e Mineracao, a niobium operation in Brazil, from 40 percent to 35 percent for $27 million in net cash proceeds. We recorded an after-tax gain of $2 million.

In February 2005, we sold our Unocal Bharat Limited ("Unocal Bharat") subsidiary, which held our 26 percent equity interest in Hindustan Oil Exploration Company ("HOEC") and received $25 million in net cash proceeds. HOEC is India's only publicly traded oil and gas exploration and production company. We recorded an after-tax gain of $22 million.

5. Income Taxes

Income taxes on earnings from continuing operations for the second quarter and six month periods of 2005 were $273 million and $505 million, respectively, compared with $138 million and $309 million for the comparable periods of 2004. The effective income tax rates for the second quarter and six month periods of 2005 were 38 percent and 37 percent, respectively, compared with 34 percent and 37 percent for the same periods a year ago. The overall higher effective tax rate in the second quarter of 2005 compared to 2004 is due primarily to a net deferred benefit of $27 million recorded in the second quarter of 2004 for settlements and assessments with various taxing authorities. The effective tax rate for the six months of 2005 included net tax related benefits accrued related to the sale of Unocal Bharat and other assets along with the tax benefit effect of currency related adjustments in Thailand. The effective income tax rate for the six month period of 2004 included the effect of the aforementioned net deferred tax benefit of $27 million as well as the tax benefit effect in 2004 of currency related adjustments in Thailand.

6. Discontinued Operations

In May 2005, we announced our intention to sell our Western Canadian exploration and production assets, and, in July 2005, we entered into an agreement to sell all of the outstanding capital stock in our wholly owned Canadian subsidiary, Northrock Resources Ltd. ("Northrock") (see note 21 for further detail). At June 30, 2005, these assets were held for sale (see note 11 for further detail), and we have classified the results of these operations in discontinued operations on the consolidated earnings statement. Our Western Canadian exploration and production assets generated revenues of $123 million and net earnings of $25 million in the second quarter of 2005 compared to revenues of $101 million and net earnings of $16 million in the second quarter of 2004. These assets generated revenues of $241 million and net earnings of $42 million in the six month period of 2005 compared to revenues of $202 million and net earnings of $28 million in the six month period of 2004.

In April 2005, we sold our needle coke business for $25 million in cash plus net working capital. We recorded an after-tax gain of approximately $12 million in the second quarter of 2005. The gain on disposal plus the results of operations prior to the sale are reported in discontinued operations on the consolidated earnings statement. The needle coke business generated revenues of $13 million and a net loss of $2 million in the second quarter of 2005 compared to revenues of $21 million and a net loss of $1 million in the second quarter of 2004. The needle coke business generated revenues of $54 million and net earnings of $1 million in the six month period of 2005 compared to revenues of $30 million and a net loss of $2 million in the six month period of 2004.

In June 2004, we sold certain of our prospective and producing mineral fee lands in the U.S., which included approximately 2 MBOE/d of production in Mississippi, Arkansas and Alabama. The producing portion of these mineral fee lands resulted in an after-tax gain of approximately $43 million. The gain on the asset disposal plus the results of operations prior to the sale are reported in discontinued operations on the consolidated earnings statement. These properties generated revenues of $6 million and net earnings of $3 million in the second quarter of 2004 and revenues of $12 million and net earnings of $6 million in the six month period of 2004.

In May 2004, we sold our Cal Ven Pipeline system located in Alberta, Canada and recorded an after-tax gain of approximately $13 million. The gain on disposal plus the results of operations prior to the sale are reported in discontinued operations on the consolidated earnings statement. The Cal Ven pipeline generated revenues of $1 million and net earnings of less than $1 million in 2004.

The following table summarizes the results from all our discontinued operations for the periods shown:

	For the Three Months Ended June 30,		Fot the Six Months Ended June 30,	
Millions of dollars	2005	2004	2005	2004
Revenues	$ 136	$ 128	$ 295	$ 245
Total costs and other deductions	90	102	213	195
Earnings from discontinued operations before income taxes	46	26	82	50
Income taxes on discontinued operations	23	8	39	18
Earnings from discontinued operations	23	18	43	32
Gain on disposal of discontinued operations before income taxes	19	84	23	84
Income taxes on disposal of discontinued operations	7	28	9	28
Gain on disposal of discontinued operations	12	56	14	56
Total earnings from discontinued operations	$ 35	$ 74	$ 57	$ 88

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7. 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 quarter and six month periods ended June 30, 2005 and 2004:

Millions of dollars except per share amounts	Earnings (Numerator)	Shares (Denominator)
Three months ended June 30, 2005		
Earnings from continuing operations	$ 440	272
Basic EPS		
Effect of dilutive securities		
Options and common stock equivalents		3
Diluted EPS	$ 440	275
Three months ended June 30, 2004		
Earnings from continuing operations	$ 267	264
Basic EPS		
Effect of dilutive securities		
Options and common stock equivalents		2
	267	266
Interest on convertible debentures payable to trust (after-tax)	7	12
Diluted EPS	$ 274	278

Millions except per share amounts	Earnings (Numerator)	Shares (Denominator)
Six months ended June 30, 2005		
Earnings from continuing operations	$ 872	271
Basic EPS		
Effect of dilutive securities		
Options and common stock equivalents		3
Diluted EPS	$ 872	274
Six months ended June 30, 2004		
Earnings from continuing operations	$ 522	263
Basic EPS		
Effect of dilutive securities		
Options and common stock equivalents		2
	522	265
Interest on convertible debentures payable to trust (after-tax)	14	12
Diluted EPS	$ 536	277

Certain options were not included in the computation of diluted EPS as the exercise prices were greater than average market prices of the common shares during the respective periods. The computation of diluted EPS for the three month and six month periods ended June 30, 2005 included all outstanding common stock options. For the three month and six month periods ended June 30, 2004, there were options outstanding to purchase approximately 3.6 million and 2.5 million shares, respectively, of common stock that were excluded from the computation of diluted EPS.

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8. Comprehensive Income

Unocal's comprehensive income is detailed in the following table:

	For the Three Months Ended June 30,	
Millions of dollars	2005	2004
Net earnings	$ 475	$ 341
Change in unrealized gain (loss) on hedging instruments (a)	10	(5)
Reclassification adjustment for settled hedging contracts (b)	17	17
Unrealized foreign currency translation adjustments	(5)	(21)
Minimum pension liability adjustment (c)	-	-
Total comprehensive income	$ 497	$ 332

9. Stock-Based Compensation

We began using the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," for 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 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:

	For the Three Months Ended June 30,		Fo
Millions of dollars except per share amounts	2005	2004	
Net earnings			
As reported	$ 475	$ 341	
Add: Stock-based employee compensation expense included in reported net earnings, net of related tax effects and minority interests	10	2	
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	(10)	(2)	

Pro forma net earnings	$ 475	$ 341
Net earnings per share:		
Basic - as reported	$ 1.75	$ 1.29
Basic - pro forma	$ 1.75	$ 1.29
Diluted - as reported	$ 1.73	$ 1.25
Diluted - pro forma	$ 1.73	$ 1.25

10. Cash and Cash Equivalents

At June 30, 2005, our cash and cash equivalents had increased by $615 million from year-end 2004, reflecting the effect of stronger commodity prices during the first six months of 2005.

Millions of dollars	At June 30, 2005 (a)	At December 31, 2004
Cash	$ 250	$ 243
Time deposits	499	258
Marketable securities	1,026	659
Cash and cash equivalents	$ 1,775	$ 1,160

At June 30, 2005, marketable securities totaled $1.026 billion reflecting our short-term investments primarily in high-grade commercial paper and money market funds. The money market funds invest in U.S. Treasury and other U.S. government agency obligations, floating rate and variable rate demand notes of U.S. and foreign corporations, commercial paper, certificates of deposit and time deposits, asset backed securities and repurchase agreements. The funds are rated "Aaa" by Moody's Investors Service, Inc. and/or "AAAm" by Standard & Poor's Ratings Services. Our commercial paper investments are rated in the highest category by Moody's Investor Services, Inc. (P1) and Standard & Poor's Ratings Services (A1). All short-term investments are highly liquid and are part of our cash management portfolio with original maturities of three months or less.

11. Assets Held for Sale

At June 30, 2005, we held for sale our exploration and production assets in Western Canada. On July 8, 2005, we entered into a Share Purchase Agreement with Pogo to sell all of the outstanding capital stock in our wholly owned Northrock subsidiary (see note 21 for further detail).

At June 30, 2005, the assets and liabilities of this business were:

Millions of dollars	Northrock Resources Ltd.
Assets held for sale	
Cash	$ 28
Accounts and notes receivable	53

Inventories	5
Other current assets	1
Investments and long-term receivables - net	2
Properties - net (a)	1,223
Goodwill	54
Other assets	6
Total	$ 1,372
Liabilities held for sale	
Accounts payable	$ 65
Taxes payable	14
Deferred income taxes	287
Accrued abandonment, restoration and environmental liabilities	38
Other deferred credits and liabilities	7
Total	$ 411

We have classified the results from operations of these assets as a discontinued operation (see note 6 for further detail).

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12. Properties and Capital Leases

As of January 1, 2005, we adopted FASB Staff Position FAS 19-1, "Accounting for Suspended Well Costs." Upon adoption of the FSP, we evaluated all existing capitalized exploratory well costs under the provisions of the FSP. As a result, we determined that all these costs met the criteria for capitalization under the FSP. The following table reflects the net changes in capitalized exploratory well costs during the first six months of 2005 and 2004, and does not include amounts that were capitalized and subsequently expensed or reclassified in the same period. Capitalized exploratory well costs at June 30, 2004, are presented based on our previous accounting policy.

	For the Six Months Ended June 30,	
Millions of dollars	2005	2004
Beginning balance at January 1	$ 355	$ 364
Additions to capitalized exploratory well costs pending the determination of proved reserves	19	99
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(8)	(4)
Capitalized exploratory well costs charged to expense	(5)	(16)
Ending balance at June 30 (a)	$ 361	$ 443

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since completion of drilling:

Millions of dollars	For the Six Months Ended June 30, 2005	2004
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 21	$ 132
Capitalized exploratory well costs that have been capitalized for a period greater than one year	340	311
Balance at June 30	$ 361	$ 443
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	11	11

At June 30, 2005, the aging of the $340 million balance of capitalized exploratory well costs for suspended wells exceeding one year based on the date drilling was completed consisted of $94 million in 2004; $49 million in 2003; $56 million in 2002; $77 million in 2001; $44 million in 2000; $16 million in 1999 and $4 million in 1997.

Exploratory well costs that continue to be capitalized for more than one year after completion of drilling at June 30, 2005, consist of the following: United States ($125 million for 4 projects); Indonesia ($145 million for 4 projects); Thailand ($41 million for 1 project); Vietnam ($23 million for 1 project); and Canada ($6 million for 1 project). An overview of the activities that have been undertaken to evaluate the major projects and potential reserves and the information still required to classify the associated reserves as proved appears in note 11 of our Form 10-Q for the quarterly period ended March 31, 2005.

13. Postemployment Benefit Plans

We have numerous plans worldwide that provide employees with retirement benefits. We also have medical plans that provide health care benefits for eligible employees and many of our retired employees. Most of our plans covering employees outside of North America are unfunded and resulting liabilities are extinguished on a "pay as you go" basis.

The components of net periodic benefit cost for our pension and postretirement medical plans for the three month and six month periods ended June 30, 2005 and 2004 were:

	For the Three Months Ended June 30,			
	Pension Benefits		Other Benefits	
Millions of dollars	2005	2004	2005	2004
Service cost (net of employee contributions)	$ 10	$ 8	$ -	$ 1
Interest cost	20	20	4	5
Expected return on plan assets	(20)	(19)	-	-

Amortization of:	-	-	-	-
Prior service cost	2	2	(1)	-
Net actuarial losses	15	14	1	2
Curtailment and settlement losses	-	-	-	-
Net periodic pension and other benefit costs	$ 27	$ 25	$ 4	$ 8

	For the Six Months Ended June 30,			
	Pension Benefits		Other Benefits	
Millions of dollars	2005	2004	2005	2004
Service cost (net of employee contributions)	$ 20	$ 16	$ 1	$ 2
Interest cost	40	40	8	10
Expected return on plan assets	(40)	(38)	-	-
Amortization of:	-	-	-	-
Prior service cost	3	3	(3)	-
Net actuarial losses	32	30	2	4
Curtailment and settlement losses	-	-	-	-
Net periodic pension and other benefit costs	$ 55	$ 51	$ 8	$ 16

In the second half of 2004, we recorded a full year benefit of $11 million representing the impact of the non-taxable federal subsidy provided for under the "The Medicare Prescription Drug, Improvement and Modernization Act of 2003." In keeping with the guidance provided by FSP No. 106-2, the net periodic benefit cost for our U.S. postretirement medical program for the three month and six month periods ended June 30, 2004 has been restated to include the impact of the subsidy.

The assumed weighted-average rates used to determine the net periodic benefit costs were:

	Pension Benefits		Other Benefits	
Weighted-average assumptions	2005	2004	2005	2004
Discount rates	5.74%	6.00%	5.75%	6.00%
Rates of salary increases	4.91%	4.91%	4.99%	4.99%
Expected returns on plan assets	8.00%	8.00%	N/A	N/A

In the six months ended June 30, 2005, no contributions were made to the U.S. Qualified Retirement Plan. Under existing funding regulations, we are not required to make any cash contributions to our U.S. Qualified Retirement Plan in 2005.

We previously disclosed in Item 8 of our 2004 10-K in the consolidated financial statements under note 16 that we expected to contribute approximately $5 million to our Supplemental Executive Retirement Plan, approximately $17 million to our foreign pension plans and approximately $25 million to our worldwide postretirement medical plans in 2005. As of June 30, 2005, we anticipate that actual contributions to our Supplemental Executive Retirement plans for the full year 2005 will approximate $70 million while contributions to our foreign pension and worldwide postretirement medical plans will not vary materially from the forecasted levels at year-end 2004.

14. Long Term Debt

Unocal's total consolidated debt, including current maturities, was $2.54 billion at June 30, 2005, compared with $3.06 billion at the end of 2004. In 2005, we paid a combination of cash and Unocal common stock to retire the $242 million outstanding balance of the 6-1/4% convertible junior subordinated debentures (see note 15 for further detail). We retired $85 million in 7.20 percent notes that matured in the first six months of 2005. We paid $77 million as full payment under the revolving portion of our Canadian dollar-denominated credit agreement. In addition, we paid $76 million in medium term notes that matured in the first six months of 2005. Finally, we paid $26 million related to

a limited recourse loan for our West Seno project in Indonesia and $9 million related to a non-recourse loan from one of our Geothermal segment subsidiaries.

15. Variable Interest Entities

In January 2005, Unocal Capital Trust (the "Trust") completed the redemption of its outstanding convertible preferred securities. Holders converted 4,550,738 preferred securities into Unocal common stock and redeemed 119,143 preferred securities for $6 million. Including the 1.25 percent redemption premium and unpaid distributions, the total cash cost of the redemption was $6 million. In connection with the redemption program completion, Unocal redeemed $242 million of its convertible junior subordinated debentures held by the Trust using cash on hand and by issuing Unocal common stock in January 2005 upon the conversion by holders of their preferred securities. The Trust utilized the common stock and cash it received from Unocal to redeem the preferred securities and to retire the Trust's common securities, which Unocal held as an investment.

16. Accrued Abandonment, Restoration and Environmental Liabilities

At June 30, 2005, we had accrued $739 million in estimated abandonment and restoration costs as liabilities. At December 31, 2004, we had accrued $762 million in estimated abandonment and restoration costs. The decrease in the liability account reflects a reclassification of $38 million as a liability of assets held for sale (see note 11 for further detail). The account also reflects an increase in the liability from December 31, 2004 due to $21 million in accrued pre-tax accretion expense and $10 million in new abandonment liabilities recorded during the period. These amounts were partially reduced by abandonment liability settlements totaling $13 million and downward revisions to existing estimates of $3 million during the first six months of 2005.

Our reserve for environmental remediation obligations at June 30, 2005 totaled $239 million, of which $112 million was included in current liabilities. This compared with $244 million at December 31, 2004, of which $109 million was included in current liabilities. The following table shows the environmental remediation obligations by category:

	At June 30,	At December 31,
Millions of dollars	2005	2004
Superfund and similar sites	$ 12	$ 14
Active Company facilities	25	30
Company facilities sold with retained liabilities and former Company-operated sites	100	101
Inactive or closed Company facilities	102	99

Total	$ 239	$ 244

17. Commitments and Contingencies

Unocal has contingent liabilities for existing or potential claims, lawsuits and other proceedings, including those involving environmental, tax, guarantees and other matters, some of which are discussed more specifically below. We accrue liabilities when it is probable that future costs will be incurred and these costs can be reasonably estimated. Accruals are based on developments to date, our estimates of the outcomes of these matters and our 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 our future results of operations, financial condition or liquidity.

Environmental matters

We continue to move forward to address environmental issues for which we are responsible. In cooperation with regulatory agencies and others, we follow procedures that we have established to identify and cleanup contamination associated with past operations. We are 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 us or owned by others and are associated with past and present operations, including sites at which we have 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 we are able to determine whether we are 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 our 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 we are usually just one of a number of companies identified as a PRP, or other reasons.

Assessment and Remediation

As disclosed in note 16, at June 30, 2005, we had accrued $239 million for estimated future environmental assessment and remediation costs at various sites where liabilities for such costs are probable and reasonably estimable. The amount accrued represents our reserve for assessment and remediation obligations 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. We 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, we estimate that we could incur possible additional remediation costs aggregating approximately $235 million. The amount of such possible additional costs reflects the aggregate of the high ends of the ranges of costs of feasible alternatives that we identified 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 we are 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 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, the amounts reserved and the possible additional estimated costs may change in the near term, and in some cases could change substantially.

During the first six months of 2005, cash payments of $48 million were applied against the reserves and $43 million was added to the reserves. Possible additional remediation costs increased by $20 million during the first six months of 2005. The accrued costs and the estimated possible additional costs are shown below for four categories of sites:

	At June 30, 2005	
Millions of dollars	Reserve	Possible Additional Costs
Superfund and similar sites	$ 12	$ 15
Active Company facilities	25	35
Company facilities sold with retained liabilities and former Company-operated sites	100	80
Inactive or closed Company facilities	102	105
Total	$ 239	$ 235

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 we have a contractual agreement to pay a share of the remediation costs. For these sites, we generally have less control over the timing of the work and consequently the timing of the associated payments. Based on available information, we estimate that the majority of the amounts included in the reserve will be paid within the next three to five years.

At the sites where we have contractual agreements to share remediation costs with third parties, the reserve reflects our 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 we sold facilities or a business to a third party, sharing of remediation costs for those sites may be included in the sales agreement.

Superfund and similar sites

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 we may be one. We have been notified that we are a PRP at the sites included in this category. At the sites where we have not denied liability, our contribution to the contamination at these sites was primarily from operations in the other categories described below. Included in this category of sites are:

- the McColl site in Fullerton, California
- the Operating Industries site in Monterey Park, California
- the Casmalia Waste site in Casmalia, California.

At June 30, 2005, we have received notifications from the EPA that we may be a PRP at 21 sites and may share certain liabilities at these sites. Of the total, three sites are under investigation and/or litigation, and our potential liability is not presently determinable. Of the remaining 18 sites, where we have concluded that liability is probable and to the extent costs can be reasonably estimated, a reserve of $8 million has been established for future remediation and settlement costs.

Various state agencies and private parties have identified 23 other similar PRP sites. Four sites are under investigation and/or litigation, and our potential liability is not presently determinable; and at three sites, our potential liability appears to be de minimis. Where we have concluded that liability is probable and to the extent costs can be reasonably estimated at the remaining 16 sites, a reserve of $4 million has been established for future remediation and settlement costs.

The sites discussed above exclude 132 sites where our liability has been settled, or where we have 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.

We do not consider the number of sites for which we have been named a PRP as a relevant measure of liability. Although the liability of a PRP is generally joint and several, we are usually just one of numerous companies designated as a PRP. Our 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 our ultimate costs.

Active Company facilities

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. Included in this category are:

- the Molycorp molybdenum mine in Questa, New Mexico
- the Molycorp lanthanide facility in Mountain Pass, California
- Alaska oil and gas properties.

We have a reserve of $25 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. We recorded provisions of $2 million during the first six months of 2005. During the first six months of 2005, we made payments of $7 million for this category of sites.

Company facilities sold with retained liabilities and former Company operated sites

The "Company facilities sold with retained liabilities and former Company-operated sites" category includes our former 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 this category are former oil and gas fields that we no longer operate. 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 and agricultural chemical retail businesses. Included in this category are:

- West Coast refining, marketing and transportation sites
- auto/truckstop facilities in various locations in the U.S.
- industrial chemical and polymer sites in the South, Midwest and California
- agricultural chemical sites in the West and Midwest.

In each sale, we retained a contractual remediation or indemnification obligation and are responsible only for certain environmental issues 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 we retained certain levels of remediation liabilities; and/or identified in subsequent claims made by buyers of the properties. Our former operated sites include service stations, distribution facilities and oil and gas fields that we previously operated but did not own.

We have an aggregate reserve of $100 million for this group of sites. During the first six months of 2005, provisions of $25 million for this category were recorded. These provisions were primarily for sites that we formerly operated and were based on new and revised cost estimates that we identified during 2005 for the remediation of approximately 125 service station, bulk plant and terminal sites and for the assessment and remediation of oil and gas fields in Central California. Payments of $26 million were made during the first six months of 2005 for sites in this category.

Inactive or closed Company facilities

The "Inactive or closed Company facilities" category includes former oil and gas fields and other locations that are no longer operating. In most cases, these sites are contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Other sites in this category were contaminated from former ferromolybdenum production operations. Included in this category are:

- the Guadalupe oil field on the central California coast
- the Molycorp Washington facility in Pennsylvania
- the Beaumont Refinery in Texas.

A reserve of $102 million has been established for these types of facilities. During the first six months of 2005, we accrued $15 million related to sites in this category, primarily for the Guadalupe oil field site. Soil at this site has been contaminated with diluent, a kerosene-like additive used in the field's former operations. The provision includes revised estimated costs for remediation work that is required by the cleanup and abatement order for the site. The required remediation work has become better defined through ongoing and continuing meetings and negotiations with the regulatory agencies. This work includes studies, operation and maintenance of remedial systems, restoration, and regulatory agency oversight and permitting procedures. Payments of $12 million were made during the first six months of 2005 for sites in this category.

Legal Compliance

We are subject to federal, state and local environmental laws and regulations, including CERCLA, as amended, RCRA and laws governing low-level radioactive materials. Under these laws, we are 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 our facility in Beaumont, Texas, a former agricultural chemical facility in Corcoran, California, Molycorp's facility in Washington, Pennsylvania and other facilities. In addition, Molycorp is required to decommission its Washington facility in Pennsylvania pursuant to the terms of its radioactive source materials license and decommissioning plan.

We also must provide financial assurance for future closure and post-closure costs of our RCRA-permitted facilities and for decommissioning costs at Molycorp's Washington Pennsylvania facility under its radioactive source materials license. Pursuant to a 1998 settlement agreement between us and the State of California (and the subsequent stipulated judgment entered by the Superior Court), we must provide financial assurance for anticipated costs of remediation activities at our former Guadalupe oil field. As previously discussed, remediation reserves for these sites are included in the "Inactive or closed Company facilities" category and totaled $88 million at June 30, 2005. At those sites where investigations or feasibility studies have advanced to the stage of analyzing alternative remedies and/or ranges of costs, we estimate that we could incur possible additional remediation costs aggregating approximately $75 million. Although any possible additional costs for these sites are likely to be incurred at different times and over a period of many years, we believe that these obligations could have a material adverse effect on our results of operations but are not expected to be material to our consolidated financial condition or liquidity.

Insurance

We maintain 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 our contingent legal exposures enumerated above are uninsurable either due to insurance policy limitations, public policy or market conditions, our management believes that our current insurance program significantly reduces the possibility of an incident causing us a material adverse financial impact.

Certain Litigation and Claims

Petrobangla Claim: Our subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. received a letter from Petrobangla claiming, on behalf of itself and the Bangladesh government, 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 exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. Unocal and OBL believe that the claim vastly overstates the amount of recoverable natural gas involved in the blowout. For a further discussion of this claim, refer to the "Petrobangla Claim" section under note 23 to the consolidated financial statements in Item 8 of our 2004 10-K.

Chevron Merger Litigation: Unocal and its ten directors are defendants in two putative class action lawsuits challenging the acquisition of Unocal by Chevron. Initial complaints were brought by individual Unocal stockholders in April 2005 in the Superior Court of California in Los Angeles. The actions were consolidated and a consolidated complaint was filed on July 14, 2005 alleging that Unocal and its directors breached their fiduciary duties by (i) failing to maximize stockholder value; (ii) securing benefits for certain officers and directors of Unocal at the expense of its stockholders; and (iii) improperly favoring Chevron over other potential bidders by tailoring the merger agreement to Chevron and erecting obstacles to deter other interested bidders. In general terms, the plaintiffs challenge the acquisition price, officer compensation, and the size of the termination fee contained in the Chevron merger agreement.

The consolidated complaint brings a single claim of breach of fiduciary duties. The lawsuit, Lieb v. Unocal et al., seeks equitable relief by way of an injunction against the Chevron merger, an order directing Unocal to obtain a transaction more favorable to Unocal's stockholders, an order to set aside the merger if consummated and the imposition

of a constructive trust, as well as unspecified amount of damages to Unocal's stockholders sustained as a result of the Chevron merger and attorney's fees.

On July 27, 2005, a separate lawsuit was filed in federal court in Los Angeles, purportedly brought on behalf of a class of Unocal stockholders. The action, entitled Alaska Electrical Pension Fund v. Unocal Corp., et al., Case No. CV05-5420 JFW, asserts claims and allegations, and seeks relief, substantially similar to the consolidated actions filed in California state court, which are described above. We believe we have substantial meritorious defenses to the claims.

Unocal and Chevron have reached an agreement in principle with the state court plaintiffs providing for the settlement of the putative stockholder class action brought in California state court in connection with the proposed Chevron merger. In connection with the settlement, it was agreed that Unocal would make certain disclosures, which are set forth in the Additional Disclosure Relating to the Proposed Merger with Chevron Corporation filed with the SEC on July 29, 2005. Further, under the terms of settlement, and subject to certain conditions, all claims relating to the merger agreement and the proposed merger will be dismissed and released on behalf of the settlement class and the state court plaintiffs will withdraw their challenges to the proposed merger. The settlement is subject to California state court approval. Prior to the time at which the settlement will be submitted to the California state court for final approval, additional information will be provided to class members in a notice of settlement.

Tax Matters

We believe we have adequately provided in our accounts for tax items and issues not yet resolved. Several prior material tax issues are unresolved. Resolution of these tax issues affects not only the year in which the items arose, but also our tax situation in other tax years.

With respect to the 1979-1994 taxable years, the Joint Committee on Taxation of the U.S. Congress reviewed and approved the settlement of all issues for these years, including the carryback of a 1993 net operating loss to taxable year 1984 and resultant credit adjustments, as previously agreed with the Appeals division of the Internal Revenue Service ("IRS"). This settlement and corresponding recalculation of taxable income and credits for this period resulted in an overpayment of taxes. We received cash refunds of $72 million in 2004 and $6 million in 2005, representing overpaid taxes plus interest thereon. Taxable years 1979-1990 are now closed and barred from additional assessment of federal income taxes. Although the IRS has completed its audit of Unocal for taxable years 1991-1994 and a settlement has been reached for all such years, these years cannot be formally closed until a separate audit by the IRS of the Alaska Kuparuk River Unit tax partnership is closed. The Kuparuk tax partnership audit has been completed and is in the process of being closed. No material adjustments to taxable income are required. However, until this tax partnership audit is formally closed, our corporate tax audit remains technically open. Accordingly, the IRS refers to the 1991-1994 taxable years as "partially closed." All such developments have been considered in our accounts.

With respect to the 1995-1997 taxable years, a settlement of all issues was reached with the Appeals division of the IRS. Although the IRS has completed its audit of Unocal for taxable years 1995-1997 and a settlement has been reached for all such years, these years cannot be formally closed until a separate audit by the IRS of the Alaska Kuparuk River Unit tax partnership is closed. The Kuparuk tax partnership audit has been completed and is in the process of being closed. No material adjustments to taxable income are required. However, until this tax partnership audit is formally closed, our corporate tax audit remains technically open. Accordingly, the IRS refers to the 1995-1997 taxable years as "partially closed." All such developments have been considered in our accounts.

The 1998-2001 taxable years are before the Exam division of the IRS.

Guarantees Related to Assets or Obligations of Third Parties

Future Remediation Costs

We have 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 we either leased property from or sold property to these third parties. The properties may or may not have been contaminated by our former operations. Where it has been or will be determined that we are responsible for contamination, the guarantees require us 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 we 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.

We have 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 our reserve for environmental remediation obligations.

At June 30, 2005, the reserve for this category totaled $100 million. For those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, we estimate that we could incur possible additional remediation costs aggregating approximately $80 million.

BTC Construction Completion Guarantee

We have a construction completion guarantee related to debt financing arrangements for the Baku-Tiblisi-Ceyhan ("BTC") crude oil pipeline project. We have an equity interest in the development of this pipeline from Baku, Azerbaijan through Georgia to the Mediterranean port of Ceyhan, Turkey. Our maximum potential future payments under the guarantee are estimated to be $310 million. The debt is secured by transportation proceeds from production of the Azeri field in the Caspian Sea. The debt is non-recourse upon financial completion certification, which is expected by 2009. As of June 30, 2005, we have recorded a liability of $19 million as the estimated value of this guarantee.

Other Guarantees and Indemnities

We have also guaranteed the debt of certain other entities accounted for by the equity method. The majority of this debt matures ratably through the year 2014. The maximum potential amount of future payments we could be required to make is $14 million.

In the ordinary course of business, we have agreed to indemnify cash deficiencies for certain domestic pipeline joint ventures, which we account for on the equity method. These guarantees are considered in our analysis of overall risk. Because 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, we believe the payments would not have a material adverse impact on our financial condition or liquidity.

Financial Assurance for Unocal Obligations

Surety Bonds and Letters of Credit

In the normal course of business, we have performance obligations that 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 us if drawn upon. At June 30, 2005, we had obtained various surety bonds for $166 million. These surety bonds included a bond for $58 million securing our performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of natural gas over a ten-year period that began in January of 1999 and will end in December of 2008 and $108 million in various other routine performance bonds held by local, city, state and federal agencies. We also had obtained $121 million in standby letters of credit at June 30, 2005, of which $29 million represented letters of credit with the revenue department in Thailand relating to tax appeals, $41 million represented letters of credit for collateral and margin requirements for crude oil and natural gas purchases and $12 million represented additional collateral related to the aforementioned bond for the fixed price natural gas sales contract. We have entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit.

Other Guarantees and Credit Rating Triggers

We have various other guarantees for approximately $500 million. Approximately $118 million of the $500 million in guarantees represent financial assurance we gave on behalf of our Molycorp subsidiary relating to permits covering operations and discharges from Molycorp's Questa, New Mexico, molybdenum mine. Our 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 $280 million of the $500 million would require us to obtain a surety bond or a letter of credit or establish a trust fund if our 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.

Classification on Balance Sheet

Approximately $240 million of the surety bonds, letters of credit and other guarantees that we are 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

Our lease agreement for the Discoverer Spirit deepwater drillship has a current minimum daily rate of approximately $229,000. The future remaining minimum lease payment obligation was $18 million at June 30, 2005. The contract will expire on September 18, 2005.

We also have other contingent liabilities for litigation, claims and contractual agreements arising in the ordinary course of business. Based on management's assessment of the ultimate amount and timing of possible adverse outcomes and associated costs, none of these other matters is presently expected to have a material adverse effect on our consolidated financial condition, liquidity or results of operations.

18. Financial Instruments and Commodity Hedging

Interest rate contracts - We enter into interest rate swap contracts to manage our debt with the objective of minimizing the volatility and magnitude of our borrowing costs. We may also enter into interest rate option contracts to protect our interest rate positions, depending on market conditions. At June 30, 2005, we had approximately $19 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, approximately $3 million in after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months.

Foreign currency contracts - Various foreign exchange currency forward, option and swap contracts are entered into from time to time to manage our exposures to adverse impacts of foreign currency fluctuations on recognized obligations and anticipated transactions. At June 30, 2005, we had no deferred amounts in accumulated other comprehensive income on the consolidated balance sheet related to foreign currency contracts.

Commodity hedging activities - We use hydrocarbon derivatives to mitigate our overall exposure to fluctuations in hydrocarbon commodity prices. Ineffectiveness for cash flow and fair value hedges was immaterial for the six months of 2005. At June 30, 2005, we had $9 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 2005 through December 2005. All of the after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months.

Fair values for debt and other long-term instruments - The estimated fair values of our long-term debt and capital leases were $2.80 billion at June 30, 2005. Fair values were based on the discounted amounts of future cash outflows using the rates offered to us for debt with similar remaining maturities.

19. Supplemental Condensed Consolidating Financial Information

Unocal guarantees all the publicly held securities issued by its 100 percent-owned subsidiary 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) Union Oil (Parent) and (c) on a combined basis, the subsidiaries of Union Oil (non-guarantor subsidiaries). Virtually all of our operations are conducted by Union Oil and its subsidiaries.

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the Three Months Ended June 30, 2005

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminat
Revenues				
Sales and operating revenues	$ -	$ 416	$ 2,031	$ (
Interest, dividends and miscellaneous income	-	7	40	
Gain on sales of assets	-	2	8	
Total revenues	-	425	2,079	(
Costs and other deductions				
Purchases, operating and other expenses	3	323	1,162	(
Depreciation, depletion and amortization	-	79	190	
Impairments	-	-	1	
Dry hole costs	-	10	2	
Interest expense	-	28	9	

Total costs and other deductions	3	440	1,364	(
Equity in earnings of subsidiaries	477	524	-	(1,
Earnings from equity investments	-	(22)	40	
Earnings from continuing operations before income taxes and minority interests	474	487	755	(1,
Income taxes	(1)	4	270	
Minority interests	-	-	2	
Earnings from continuing operations	475	483	483	(1,
Earnings from discontinued operations	-	(6)	41	
Net earnings	$ 475	$ 477	$ 524	$ (1,

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the Three Months Ended June 30, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminat
Revenues				
Sales and operating revenues	$ -	$ 318	$ 1,711	$ (
Interest, dividends and miscellaneous income	1	1	19	
Gain on sales of assets	-	(40)	80	
Total revenues	1	279	1,810	(
Costs and other deductions				
Purchases, operating and other expenses	3	292	1,124	(
Depreciation, depletion and amortization	-	65	148	
Impairments	-	3	6	
Dry hole costs	-	10	26	
Interest expense	9	31	8	
Total costs and other deductions	12	401	1,312	(
Equity in earnings of subsidiaries	350	443	-	(
Earnings from equity investments	-	2	37	
Earnings from continuing operations before income taxes and minority interests	339	323	535	(
Income taxes	(2)	(29)	169	
Minority interests	-	-	(1)	
Earnings from continuing operations	341	352	367	(
Earnings from discontinued operations	-	(2)	76	
Net earnings	$ 341	$ 350	$ 443	$ (

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the Six Months Ended June 30, 2005

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminat
Revenues				
Sales and operating revenues	$ -	$ 818	$ 3,921	$ (
Interest, dividends and miscellaneous income	-	14	45	
Gain on sales of assets	-	2	28	
Total revenues	-	834	3,994	(
Costs and other deductions				
Purchases, operating and other expenses	6	624	2,257	(
Depreciation, depletion and amortization	-	147	365	
Impairments	-	-	1	
Dry hole costs	-	11	20	
Interest expense	1	55	17	
Total costs and other deductions	7	837	2,660	(
Equity in earnings of subsidiaries	934	968	-	(1,
Earnings from equity investments	-	(21)	78	
Earnings from continuing operations before income taxes and minority interests	927	944	1,412	(1,
Income taxes	(2)	4	503	
Minority interests	-	-	4	
Earnings from continuing operations	929	940	905	(1,
Earnings from discontinued operations	-	(6)	63	
Net earnings	$ 929	$ 934	$ 968	$ (1,

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the Six Months Ended June 30, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminat
Revenues				
Sales and operating revenues	$ -	$ 644	$ 3,311	$ (
Interest, dividends and miscellaneous income	1	5	27	
Gain on sales of assets	-	(16)	100	
Total revenues	1	633	3,438	(
Costs and other deductions				
Purchases, operating and other expenses	5	521	2,208	(
Depreciation, depletion and amortization	-	128	288	

Impairments	-	6	8	
Dry hole costs	-	27	32	
Interest expense	17	57	16	
Total costs and other deductions	22	739	2,552	(
Equity in earnings of subsidiaries	628	681	-	(1,
Earnings from equity investments	-	3	73	
Earnings from continuing operations before income taxes and minority interests	607	578	959	(1,
Income taxes	(3)	(52)	364	
Minority interests	-	-	4	
Earnings from continuing operations	610	630	591	(1,
Earnings from discontinued operations	-	(2)	90	
Net earnings	$ 610	$ 628	$ 681	$ (1,

CONDENSED CONSOLIDATED BALANCE SHEET
At June 30, 2005

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elimina
Assets				
Current assets				
Cash and cash equivalents	$ 1	$ 1,174	$ 600	$
Accounts and notes receivable - net	137	190	1,077	
Inventories	-	7	235	
Assets held for sale	-	-	1,372	
Other current assets	-	88	31	
Total current assets	138	1,459	3,315	
Properties - net	-	1,910	5,899	
Other assets including goodwill	6,969	6,077	945	(12
Total assets	$7,107	$ 9,446	$ 10,159	$ (12
Liabilities and Stockholders' Equity				
Current liabilities				
Accounts payable	$ -	$ 332	$ 954	$
Current portion of long-term debt	-	185	279	
Liabilities of assets held for sale	-	-	411	
Other current liabilities	54	266	412	
Total current liabilities	54	783	2,056	
Long-term debt and capital leases	-	1,464	612	
Deferred income taxes	-	(224)	815	
Accrued abandonment, restoration and environmental liabilities	-	371	495	
Other deferred credits and liabilities	-	708	389	
Minority interests	-	-	17	

Stockholders' equity	7,053	6,344	5,775	(12
Total liabilities and stockholders' equity	$7,107	$ 9,446	$ 10,159	$ (12

CONDENSED CONSOLIDATED BALANCE SHEET
At December 31, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elimina
Assets				
Current assets				
Cash and cash equivalents	$ -	$ 691	$ 469	
Accounts and notes receivable - net	55	239	1,184	
Inventories	-	8	289	
Other current assets	-	101	26	
Total current assets	55	1,039	1,968	
Properties - net	-	1,935	6,887	
Other assets including goodwill	6,095	5,713	430	(10
Total assets	$6,150	$ 8,687	$ 9,285	$ (11
Liabilities and Stockholders' Equity				
Current liabilities				
Accounts payable	$ -	$ 278	$ 1,074	$
Current portion of long-term debt	242	162	87	
Other current liabilities	54	244	496	
Total current liabilities	296	684	1,657	
Long-term debt and capital leases	-	1,648	923	
Deferred income taxes	-	(156)	995	
Accrued abandonment, restoration and environmental liabilities	-	373	524	
Other deferred credits and liabilities	-	663	309	
Minority interests	-	-	15	
Stockholders' equity	5,854	5,475	4,862	(10
Total liabilities and stockholders' equity	$6,150	$ 8,687	$ 9,285	$ (11

CONDENSED CONSOLIDATED CASH FLOWS
For the Six Months Ended June 30, 2005

Unocal	Union Oil	Non-Guarantor

Millions of dollars	(Parent)	(Parent)	Subsidiaries	Eliminat
Cash Flows from Operating Activities				
Net cash provided by operating activities	$ 2	$ 780	$ 850	
Cash Flows from Investing Activities				
Capital expenditures and acquisitions (includes dry hole costs)	-	(149)	(724)	
Proceeds from sales of assets and discontinued operations	-	14	150	
Net cash used in investing activities	-	(135)	(574)	
Cash Flows from Financing Activities				
Change in long-term debt	(14)	(162)	(114)	
Dividends paid on common stock	(107)	-	-	
Proceeds from issuance of common stock	120	-	-	
Other	-	-	(3)	
Net cash used in financing activities	(1)	(162)	(117)	
Total increase in cash and cash equivalents	1	483	159	
Less: Cash and cash equivalents of assets held for sale	-	-	28	
Cash and cash equivalents at beginning of period	-	691	469	
Cash and cash equivalents at end of period	$ 1	$ 1,174	$ 600	

CONDENSED CONSOLIDATED CASH FLOWS
For the Six Months Ended June 30, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminat
Cash Flows from Operating Activities				
Net cash provided by operating activities	$ 7	$ 613	$ 506	
Cash Flows from Investing Activities				
Capital expenditures and acquisitions (includes dry hole costs)	-	(131)	(670)	
Proceeds from sales of assets and discontinued operations	-	28	250	
Return of capital from affiliate company	-	-	48	
Net cash used in investing activities	-	(103)	(372)	
Cash Flows from Financing Activities				
Change in long-term debt	-	(193)	87	
Dividends paid on common stock	(105)	-	-	
Proceeds from issuance of common stock	94	-	-	
Repurchases of common stock	(20)	-	-	
Other	24	(2)	(1)	

Net cash provided by (used in) financing activities	(7)	(195)	86
Increase in cash and cash equivalents	-	315	220
Cash and cash equivalents at beginning of period	1	45	358
Cash and cash equivalents at end of period	$ 1	$ 360	$ 578

20. Segment Data

Our reportable segments are: (1) Exploration and Production, (2) Midstream and Marketing, and (3) Geothermal. General corporate overhead, unallocated costs and other miscellaneous operations, including real estate, carbon and minerals and those businesses that were sold or being phased-out, are included under the Corporate and Other heading. On July 8, 2005, we entered into a Share Purchase Agreement with Pogo to sell all of the outstanding capital stock in our Northrock subsidiary in Canada. This transaction includes our exploration and production assets in Western Canada (see note 21 for further detail).

Segment Information For the Three Months Ended June 30, 2005	Exploration and Production					
	North America			International		
Millions of dollars	U.S.	Canada	Total N.A.	Asia	Other	Total Int
Sales & operating revenues	$ 303	$ 1	$ 304	$ 546	$ 111	$ 657
Other income (loss) (a)	-	-	-	(1)	11	10
Inter-segment sales & operating revenues	286	-	286	184	-	184
Total	589	1	590	729	122	851
Earnings from equity investments	-	-	-	15	-	15
Earnings (loss) from continuing operations	146	-	146	294	53	347
Earnings from discontinued operations (net)	-	25	25	-	-	-
Net earnings (loss)	146	25	171	294	53	347
Assets (at June 30, 2005)	3,323	1,372	4,695	3,758	1,195	4,953

	Midstream and Marketing (b)	Geothermal	Corporate and Other			
			Admin & General	Net Interest Expense	Environ-mental & Litigation	Other(
Sales & operating revenues	$ 1,108	$ 45	$ -	$ -	$ -	$ 47
Other income (loss) (a)	28	(1)	-	11	-	4
Inter-segment sales & operating revenues	46	-	-	-	-	(516)

Total	1,182	44	-	11	-	(465)
Earnings from equity investments	(9)	-	-	-	-	12
Earnings (loss) from continuing operations	20	17	(28)	(21)	(27)	(14)
Earnings from discontinued operations (net)	-	-	-	-	-	10
Net earnings (loss)	20	17	(28)	(21)	(27)	(4)
Assets (at June 30, 2005)	1,225	487	-	-	-	2,409

Segment Information For the Three Months Ended June 30, 2004	Exploration and Production					
	North America			International		
Millions of dollars	U.S.	Canada	Total N.A.	Asia	Other	Total Int
Sales & operating revenues	$ 197	$ 1	$ 198	$ 356	$ 79	$ 435
Other income (loss) (a)	35	-	35	1	1	2
Inter-segment sales & operating revenues	229	-	229	100	-	100
Total	461	1	462	457	80	537
Earnings from equity investments	-	-	-	12	2	14
Earnings (loss) from continuing operations	108	-	108	137	29	166
Earnings from discontinued operations (net)	46	16	62	-	-	-
Net earnings (loss)	154	16	170	137	29	166
Assets (at December 31, 2004)	3,307	1,376	4,683	3,661	1,007	4,668

	Midstream and Marketing (b)	Geothermal	Corporate and Other			
			Admin & General	Net Interest Expense	Environ-mental & Litigation	Other(
Sales & operating revenues	$ 969	$ 124	$ -	$ -	$ -	$ 73
Other income (loss) (a)	3	13	-	4	-	2
Inter-segment sales & operating revenues	38	-	-	-	-	(367)
Total	1,010	137	-	4	-	(292)
Earnings from equity investments	12	(2)	-	-	-	14
Earnings (loss) from continuing operations	18	57	(21)	(33)	(11)	(17)
Earnings from discontinued operations (net)	13	-	-	-	-	(1)

Net earnings (loss)	31	57	(21)	(33)	(11)	(18)
Assets (at December 31, 2004)	1,303	573	-	-	-	1,874

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Segment Information For the Six Months Ended June 30, 2005	Exploration and Production					
	North America			International		
Millions of dollars	U.S.	Canada	Total N.A.	Asia	Other	Total Int
Sales & operating revenues	$ 607	$ 4	$ 611	$ 1,005	$ 209	$ 1,214
Other income (loss) (a)	4	-	4	(10)	18	8
Inter-segment sales & operating revenues	538	-	538	357	-	357
Total	1,149	4	1,153	1,352	227	1,579
Earnings from equity investments	-	-	-	28	-	28
Earnings (loss) from continuing operations	300	1	301	545	101	646
Earnings from discontinued operations (net)	-	42	42	-	-	-
Net earnings (loss)	300	43	343	545	101	646
Assets (at June 30, 2005)	3,323	1,372	4,695	3,758	1,195	4,953

	Midstream and Marketing (b)	Geothermal	Corporate and Other			
			Admin & General	Net Interest Expense	Environ-mental & Litigation	Other(
Sales & operating revenues	$ 2,206	$ 88	$ -	$ -	$ -	$ 81
Other income (loss) (a)	30	-	-	19	-	20
Inter-segment sales & operating revenues	87	-	-	-	-	(982)
Total	2,323	88	-	19	-	(881)
Earnings from equity investments	7	-	-	-	-	22
Earnings (loss) from continuing operations	55	34	(57)	(36)	(39)	(32)
Earnings from discontinued operations (net)	-	-	-	-	-	15
Net earnings (loss)	55	34	(57)	(36)	(39)	(17)
Assets (at June 30, 2005)	1,225	487	-	-	-	2,409

Segment Information For the Six Months Ended June 30, 2004 Millions of dollars	Exploration and Production					
	North America			International		
	U.S.	Canada	Total N.A.	Asia	Other	Total Int
Sales & operating revenues	$ 495	$ 3	$ 498	$ 708	$ 136	$ 844
Other income (loss) (a)	45	-	45	2	2	4
Inter-segment sales & operating revenues	435	-	435	202	-	202
Total	975	3	978	912	138	1,050
Earnings from equity investments	-	-	-	22	2	24
Earnings (loss) from continuing operations	221	-	221	295	46	341
Earnings from discontinued operations (net)	49	28	77	-	-	-
Net earnings (loss)	270	28	298	295	46	341
Assets (at December 31, 2004)	3,307	1,376	4,683	3,661	1,007	4,668

	Midstream and Marketing (b)	Geothermal	Corporate and Other			
			Admin & General	Net Interest Expense	Environ-mental & Litigation	Other(
Sales & operating revenues	$ 1,918	$ 164	$ -	$ -	$ -	$ 95
Other income (loss) (a)	8	45	-	10	-	2
Inter-segment sales & operating revenues	72	-	-	-	-	(709)
Total	1,998	209	-	10	-	(612)
Earnings from equity investments	28	(1)	-	-	-	24
Earnings (loss) from continuing operations	41	94	(48)	(65)	(27)	(35)
Earnings from discontinued operations (net)	13	-	-	-	-	(2)
Net earnings (loss)	54	94	(48)	(65)	(27)	(37)
Assets (at December 31, 2004)	1,303	573	-	-	-	1,874

21. Subsequent Event

On July 8, 2005, Unocal and two of its Canadian subsidiaries entered into a Share Purchase Agreement with Pogo and one of its Canadian subsidiaries. The agreement provides that Unocal will sell all of the outstanding capital stock in its Northrock subsidiary in Canada to Pogo for US$1.8 billion in cash. For a copy of the agreement and additional information regarding the pending sale, refer to our current report on Form 8-K, filed with the SEC on July 12, 2005.

On July 29, 2005, we repaid our $200 million Canadian dollar-denominated term loan which was scheduled to mature in November 2009. The amount repaid translated to $163 million, using the applicable foreign exchange rate.

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

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with Management's Discussion and Analysis in Item 7 of our 2004 10-K and the consolidated financial statements and related notes therein. Our 2004 10-K contains a discussion of other matters not included herein, such as disclosures regarding critical accounting policies and estimates, contractual obligations and our credit facilities and other financing sources. You should read the following discussion and analysis together with the cautionary statement under "Forward-Looking Statements" on page iii of this report, which is incorporated into this item 2.

RECENT DEVELOPMENTS

Pending Merger with Chevron

On April 4, 2005, we entered into a merger agreement with Chevron Corporation and Blue Merger Sub Inc., a direct wholly-owned subsidiary of Chevron. The merger agreement provides that, upon the terms and subject to the conditions set forth in the merger agreement, Unocal would merge with and into Blue Merger Sub and the separate corporate existence of Unocal would cease, with Blue Merger Sub remaining as the surviving corporation in the merger.

On June 22, 2005, Unocal received an unsolicited competing proposal from CNOOC Limited ("CNOOC"), an affiliate of China National Offshore Oil Company, to acquire all outstanding shares of Unocal for $67 per share in cash. On June 23, 2005, Chevron granted Unocal a waiver under the Chevron merger agreement enabling Unocal, at any time prior to the date of the Unocal stockholder vote on the merger with Chevron, to negotiate with CNOOC and its representatives without the need for Unocal's board to make certain threshold determinations that otherwise would be required under the Chevron merger agreement.

On July 1, 2005, we filed with the SEC a final joint proxy statement/prospectus for the special meeting of Unocal stockholders, scheduled for August 10, 2005, to vote on the Chevron merger.

On July 19, 2005, following discussions and negotiations with CNOOC with respect to the CNOOC proposal as well as negotiations with Chevron with respect to the Chevron transaction, Unocal, Chevron and Blue Merger Sub entered into an amendment to the Chevron merger agreement. This amendment has the effect of increasing the merger consideration paid to Unocal stockholders for their shares. Pursuant to the amended merger agreement, each Unocal stockholder would have the right to elect to receive, for each Unocal share:

- a combination of 0.618 of a share of Chevron common stock and $27.60 in cash;
- 1.03 shares of Chevron common stock; or
- $69 in cash.

The all-stock and all-cash elections above would be subject to proration to preserve an overall per share mix of 0.618 of a share of Chevron common stock and $27.60 in cash for all of the outstanding shares of Unocal common stock taken together.

On July 25, 2005, we filed with the SEC a supplement to our proxy statement for the special stockholders meeting to vote on the Chevron merger.

On August 1, 2005, Institutional Shareholder Services recommended that Unocal stockholders vote for the merger with Chevron.

On August 2, 2005, CNOOC withdrew its bid proposal.

Unocal and Chevron currently expect to complete the merger promptly after Unocal stockholders approve and adopt the amended merger agreement and the merger at the special meeting, currently scheduled to be held on August 10, 2005, and after the satisfaction or waiver of all other conditions to the merger. We currently expect this to occur shortly after the special meeting. However, there can be no assurance that the conditions to closing will be met or that the merger will be completed shortly after the special meeting.

The foregoing description of the merger and the merger agreement, as amended, does not purport to be complete and is qualified in its entirety by reference to the merger agreement, as amended, which has been filed as Exhibit 2.1 to our Form 8-K filed on April 7, 2005 (original merger agreement) and Exhibit 2.1 to our Form 8-K filed on July 22, 2005 (amendment no. 1 to the merger agreement). For additional information regarding the pending merger, refer to Unocal's current reports on Form 8-K, as amended, filed with the SEC on April 4, April 7, June 9, June 10, June 23, June 24, June 30, July 6, July 20, July 22, July 29 and August 1, 2005, and any subsequent current or periodic reports that may be filed by Unocal with the SEC in connection with the pending merger transaction. Please also refer to the Form S-4 registration statement filed by Chevron and the proxy statement, as supplemented, that was filed by Unocal, in each case with the SEC in connection with the pending merger transaction.

Pending Sale of Canadian Exploration and Production Business

On July 8, 2005, we entered into an agreement with Pogo to sell all of the outstanding capital stock in our wholly owned Northrock subsidiary in Canada for $1.8 billion in cash. We expect to realize after-tax proceeds from the sale of approximately $1.5 billion. Northrock represents essentially all of our Canadian oil and gas reserves and production. Northrock had reserves of 110 million BOE at year-end 2004, less than 7 percent of our worldwide hydrocarbon reserves, and average daily net production of 28,100 BOE in the second quarter of 2005. The Northrock transaction, which is subject to customary Canadian regulatory approvals, is expected to close in the third quarter of 2005.

OVERVIEW

Our primary line of business is the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids. Our principal operations are in North America and Asia. We are also a leading producer of geothermal energy in Asia. Other activities include ownership in proprietary and common carrier pipelines, natural gas storage facilities and the marketing of hydrocarbon commodities. Fluctuations in hydrocarbon commodity prices and the resulting impact on our realized prices for liquids and North America natural gas are a significant driver of our financial performance.

In addition to developments regarding our pending merger with Chevron, which have been discussed elsewhere in this report and in our other public disclosures, some of our more significant operational highlights and other activities from the first six months of 2005 are listed below:

- began crude oil and natural gas production from the Mad Dog and K-2 fields in the Gulf of Mexico,
- began production from Phase 2 of the Thailand crude oil project,
- began production from Phase 1 of the ACG crude oil project in the Azerbaijan sector of the Caspian Sea and continued progress on Phase 2 and 3 of the project,
- began line-fill of the BTC crude oil export pipeline from the Caspian Sea to Turkey,
- began natural gas and condensate production from the Moulavi Bazar field in Bangladesh,
- encountered hydrocarbons in a secondary objective at the Knotty Head well, located in Green Canyon Block 512 in the Gulf of Mexico,
- encountered hydrocarbons in an appraisal well drilled on the deepwater Mad Dog Southwest Ridge in the Gulf of Mexico, which was further delineated by three sidetracks,
- entered into a farm-in agreement for acreage in the Turkey and Georgia sections of the Eastern Black Sea, and
- completed the redemption of our outstanding 6-1/4% convertible junior subordinated debentures.

Commodity Prices and Operating Results

Commodity prices remained volatile during the first six months of 2005. Commodity prices reached all-time highs in June and July of 2005. Our worldwide production increased by 9 percent in the first six months of 2005 compared to the first six months of 2004 primarily due to increased production from Thailand, Indonesia, Bangladesh and Azerbaijan. Rising production costs remain a challenge as the entire oil services industry attempts to benefit from the higher commodity price environment through pricing increases.

The following table summarizes our net daily production and average prices for our North America and International Exploration and Production business units:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
North America Net Daily Production				
Liquids (thousand barrels)				
U.S.	61	55	59	55
Canada	14	15	15	16
Total liquids	75	70	74	71
Natural gas - dry basis (million cubic feet)				
U.S.	442	511	448	512
Canada	83	83	83	83
Total natural gas	525	594	531	595
North America Average Prices (excluding hedging activities) (a)				
Liquids (per barrel)				
U. S.	$48.72	$35.91	$46.60	$33.66
Canada	$37.67	$29.89	$38.00	$29.17
Average	$46.56	$34.58	$44.85	$32.66

Natural gas (per mcf)				
U. S.	$ 5.91	$ 4.80	$ 5.68	$ 5.20
Canada	$ 6.35	$ 5.40	$ 6.02	$ 5.37
Average	$ 5.98	$ 4.88	$ 5.74	$ 5.23
North America Average Prices (including hedging activities) (a)				
Liquids (per barrel)				
U. S.	$48.04	$30.52	$46.39	$29.64
Canada	$37.67	$29.89	$38.00	$29.17
Average	$46.02	$30.38	$44.68	$29.54
Natural gas (per mcf)				
U. S.	$ 5.89	$ 4.53	$ 6.02	$ 5.34
Canada	$ 6.35	$ 5.08	$ 6.02	$ 5.06
Average	$ 5.97	$ 4.61	$ 6.02	$ 5.30

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2005	2004	2005	2004
International Net Daily Production (a)				
Liquids (thousand barrels)				
Asia	74	61	75	64
Other (b)	28	20	24	20
Total liquids	102	81	99	84
Natural gas - dry basis (million cubic feet)				
Asia	1,156	891	1,083	885
Other (b)	10	31	10	28
Total natural gas	1,166	922	1,093	913
International Average Prices (c)				
Liquids (per barrel)				
Asia	$49.77	$34.02	$47.63	$32.66
Other	$48.31	$36.01	$47.74	$34.30
Average	$49.43	$34.52	$47.66	$33.02
Natural gas (per mcf)				
Asia	$ 3.38	$ 3.02	$ 3.39	$ 2.99
Other	$ 5.45	$ 4.01	$ 5.35	$ 4.17
Average	$ 3.40	$ 3.03	$ 3.41	$ 3.01
Worldwide Net Daily Production (b)				
Liquids (thousand barrels)	177	151	173	155
Natural gas - dry basis (million cubic feet)	1,691	1,516	1,624	1,508
Barrels oil equivalent (thousands)	459	404	444	406
Worldwide Average Prices (excluding hedging activities)(d)				
Liquids (per barrel)	$48.18	$34.55	$46.43	$32.86
Natural gas (per mcf)	$ 4.20	$ 3.76	$ 4.17	$ 3.89
Worldwide Average Prices (including hedging activities) (d)				

Liquids (per barrel)	$47.94	$32.61	$46.35	$31.41
Natural gas (per mcf)	$ 4.20	$ 3.65	$ 4.26	$ 3.92

CONSOLIDATED RESULTS

Our consolidated results are driven primarily by the results of our oil and gas exploration and production business segment. The following discussion and analysis of our consolidated financial condition and results of operations should be read in conjunction with the historical financial information provided in the consolidated financial statements and accompanying notes in Item 1 of this report and in Item 8 of our 2004 10-K. Our financial performance is highly dependent on commodity prices, our exploration success and our ability to develop and produce our proved reserves. Other factors such as, but not limited to, asset sales, insurance settlements, environmental and litigation costs may, from time to time, be important factors that impact our financial performance. The following table summarizes our consolidated net earnings for the quarters and six month periods ended June 30, 2005 and 2004:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Millions of dollars	2005	2004	2005	2004
Earnings from continuing operations	$ 440	$ 267	$ 872	$ 522
Earnings from discontinued operations	35	74	57	88
Net earnings	$ 475	$ 341	$ 929	$ 610

Earnings From Continuing Operations

Second Quarter Results: 2nd quarter earnings in 2005 increased $173 million, or 65 percent, vs. 2nd quarter 2004 primarily due to the following factors:

Positive Variance Factors

- Higher worldwide commodity prices in the current quarter increased net earnings by approximately $180 million.
- International production was higher in the current quarter and contributed about $70 million in higher earnings, primarily from new production in Bangladesh, increased volumes from the ACG crude oil project in Azerbaijan and increased volumes from our Indonesia and Thailand operations.
- Lower net interest expense due primarily to lower debt levels increased net earnings by $12 million.
- Lower exploration costs due primarily to lower exploration drilling activity in Indonesia and Thailand contributed approximately $20 million in higher earnings.
- In the prior year quarter, we recorded a provision of $46 million pre-tax ($29 million after-tax) associated with the arbitration ruling regarding Agrium's Kenai, Alaska nitrogen-based fertilizer plant.

Negative Variance Factors

- o Lower United States natural gas production reduced net earnings by about $20 million in the current quarter due primarily to natural production declines.
- o After-tax environmental and litigation expenses were $28 million in the second quarter of 2005, compared with $15 million in the same period a year ago.
- o In 2004, our Geothermal segment settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines and recorded an after-tax settlement gain of $46 million.
- o In the current quarter of 2005, various tax related adjustments resulted in a charge to tax expense of approximately $10 million. In the prior year quarter, we recorded a net tax benefit of $27 million for settlements and assessments with various taxing authorities.
- o In the prior year quarter, our subsidiary, Pure Resources Inc. ("Pure"), recorded a $22 million after-tax gain from the sale of exploratory mineral fee lands.

Six Months Results: earnings in the first six months of 2005 increased $350 million, or 67 percent, vs. the first six months of 2004 primarily due to the following factors:

Positive Variance Factors

- o Higher worldwide commodity prices in 2005 increased net earnings by approximately $335 million.
- o International production was higher in 2005 and contributed about $100 million in higher earnings, primarily from new production in Bangladesh and increased volumes from the ACG crude oil project and our Indonesia and Thailand operations.
- o Lower net interest expense due primarily to lower debt levels increased net earnings by $29 million.
- o Higher results from our pipeline business along with higher margins from our North America natural gas storage business increased net earnings by $13 million.
- o Higher results from our minerals business increased net earnings by $17 million.
- o In 2004, we recorded a provision of $46 million pre-tax ($29 million after-tax) associated with the arbitration ruling regarding Agrium's Kenai, Alaska nitrogen-based fertilizer plant.

Negative Variance Factors

- o Lower United States natural gas production reduced net earnings by about $45 million in 2005 due primarily to natural production declines.
- o In 2004, we settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines and recorded an after-tax settlement gain of $46 million.
- o In 2005, various tax related adjustments resulted in a charge to tax expense of approximately $10 million, and in 2004 we recorded a net tax benefit of $27 million for settlements and assessments with various taxing authorities.
- o Higher employee related expenses reduced net earnings by about $15 million.
- o After-tax environmental and litigation expenses were $41 million in 2005, compared with $38 million in 2004.
- o The first six months of 2005 included approximately $32 million in after-tax gains from asset sales, primarily from the sale of miscellaneous oil and gas properties compared with the first six months of 2004, which included approximately $54 million in after-tax gains from asset sales, primarily from the sale of certain of Pure's exploratory mineral fee lands

in the U.S. and the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia.

- The first six months of 2004 included a $15 million gain from a litigation settlement related to a previous asset sale.

Sales and Operating Revenues From Continuing Operations

Second Quarter Results: 2nd quarter sales and operating revenues in 2005 increased by $362 million, or 20 percent, vs. 2nd quarter 2004 primarily due to the following factors:

Positive Variance Factors

- Higher average commodity prices from our exploration and production activities, excluding Canada, increased sales revenues by about $300 million. Our worldwide average realized liquids price was $48.90 per Bbl, which was an increase of $15.98 per Bbl, or 49 percent, from 2004. Our average realized liquids price included losses from our hedging activities of 26 cents and $2.15 per Bbl in 2005 and 2004, respectively. Our worldwide average realized natural gas price was $4.09 per Mcf in 2005, which was an increase of 52 cents per Mcf, or 15 percent, from the $3.57 per Mcf, realized in 2004. Our average worldwide natural gas price was not impacted by hedging activities in the second quarter of 2005 while the second quarter of 2004 included losses of 10 cents per Mcf.

- Sales and operating revenues from marketing activities were $935 million in the second quarter of 2005, compared with $851 million in the same period a year ago. The increase was primarily due to higher liquids and natural gas prices partially offset by lower marketing volume activity for both liquids and natural gas. During the second quarters of 2005 and 2004, approximately 21 percent and 28 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from outside parties by our Midstream and Marketing segment. These percentages in both periods included crude oil buy/sell transactions. Crude oil buy/sell amounts were primarily lower due to a significant decrease in volumes associated with these

transactions, which was partially offset by higher crude oil prices (see crude oil buy/sell discussions in Item 8 of our 2004 10-K in the consolidated financial statements under notes 1 and 2). These marketing activities allowed us to better manage commodity-related risk by effectively transferring commodities from production locations to industry marketing centers with higher volumes of commercial activity and greater market liquidity.

- Higher International production increased sales revenues by approximately $125 million primarily due to increased production from the ACG crude oil project in Azerbaijan and higher Thailand natural gas production compared to the second quarter of 2004.

- Higher liquids production in the United States increased sales revenues by approximately $10 million primarily due to production from deepwater fields in the Gulf of Mexico.

Negative Variance Factors

- In the United States, lower natural gas production reduced sales revenues by approximately $40 million. Most of the decline in the second quarter of 2005 was due to natural field declines.

o In 2004, our Geothermal segment settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines and recorded $77 million to sales and operating revenues as part of the pre-tax settlement gain.

Six Months Results: sales and operating revenues in 2005 increased by $681 million, or 19 percent, vs. 2004 primarily due to the following factors:

Positive Variance Factors

o Higher average commodity prices from our exploration and production activities, excluding Canada, increased sales revenues by approximately $555 million. Our worldwide average realized liquids price was $47.17 per Bbl, which was an increase of $15.51 per Bbl, or 49 percent, from 2004. Our average realized liquids price included losses from our hedging activities of 8 cents and $1.62 per Bbl in 2005 and 2004, respectively. Our worldwide average realized natural gas price was $4.17 per Mcf in 2005, which was an increase of 31 cents per Mcf, or 8 percent, from the $3.86 per Mcf, realized in 2004. Our average worldwide natural gas price included gains from our hedging activities of 10 cents and 5 cents per Mcf in 2005 and 2004, respectively.

o Sales and operating revenues from marketing activities were $1.83 billion in 2005, compared with $1.68 billion in 2004. During the first six months of 2005 and 2004, approximately 22 percent and 29 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from outside parties by our Midstream and Marketing segment. These percentages in both periods included crude oil buy/sell transactions. Crude oil buy/sell amounts were primarily lower due to a significant decrease in volumes associated with these transactions, which was partially offset by higher crude oil prices.

o Higher International production increased sales revenues by approximately $200 million primarily due to increased production from the ACG crude oil project in Azerbaijan and higher Thailand natural gas production compared to 2004.

o Higher liquids production in the United States increased sales revenues by approximately $15 million primarily due to production from deepwater fields in the Gulf of Mexico.

Negative Variance Factors

o In the United States, lower natural gas production reduced sales revenues by approximately $75 million. Most of the decline in 2005 was due to natural field declines.

o In 2004, our Geothermal segment settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines and recorded $77 million to sales and operating revenues as part of the pre-tax settlement gain.

Income Taxes

Income taxes on earnings from continuing operations for the second quarter and six month periods of 2005 were $273 million and $505 million, respectively, compared with $138 million and $309 million for the comparable periods of 2004. The effective income tax rates for the second quarter and six month periods of

2005 were 38 percent and 37 percent, respectively, compared with 34 percent and 37 percent for the same periods a year ago. The overall higher effective tax rate in the second quarter of 2005 compared to 2004 is due primarily to a net deferred tax benefit of $27 million recorded in the second quarter of 2004 for settlements and assessments with various taxing authorities. The effective tax rate for the six month period of 2005 included net tax related benefits accrued related to the sale of Unocal Bharat and other assets along with the tax benefit effect of currency related adjustments in Thailand. The effective income tax rate for the six month period of 2004 included the effect of the aforementioned net deferred tax benefit of $27 million as well as the tax benefit effect in 2004 of currency related adjustments in Thailand.

Earnings From Discontinued Operations

In May 2005, we announced our intention to sell our Western Canadian exploration and production assets, and, in July 2005, we entered into an agreement to sell all of the outstanding capital stock in our wholly owned Northrock subsidiary in Canada (see note 21 for further detail). At June 30, 2005, these assets were held for sale (see note 11 for further detail), and we have classified the results from these operations as a discontinued operation.

In April 2005, we sold our needle coke business for $25 million in cash plus net working capital. We recorded an after-tax gain of approximately $12 million in the second quarter of 2005. The gain on disposal plus the results of operations prior to the sale are reported in discontinued operations on the consolidated earnings statement.

In June 2004, we sold certain of our prospective and producing mineral fee lands in the U.S., which included approximately 2 MBOE/d of production in Mississippi, Arkansas and Alabama. The producing portion of these mineral fee lands resulted in an after-tax gain of approximately $43 million. The gain on the asset disposal plus the results of operations prior to the sale are reported in discontinued operations.

In May 2004, we also sold our Cal Ven Pipeline system located in Alberta, Canada and recorded an after-tax gain of approximately $13 million. The gain on disposal plus the results of operations prior to the sale are reported in discontinued operations.

The following table summarizes the revenues, gain on disposal and total earnings from each of these discontinued operations:

	For the Three Months Ended June 30,		Fo
Millions of dollars	2005	2004	
Revenues			
Exploration and Production - U.S.	$ -	$ 6	
- Canada	123	101	
Total Exploration and Production	$ 123	$ 107	
Midstream and Marketing - Cal Ven Pipeline	-	-	
Corporate & Other - Needle Coke Business	13	21	
Total revenues from discontinued operations	$ 136	$ 128	

Gain on disposal of discontinued operations		
Exploration and Production - U.S.	$ -	$ 43
Midstream and Marketing - Cal Ven Pipeline	-	13
Corporate & Other - Former Refining and Marketing	-	-
Corporate & Other - Needle Coke Business	12	-
Total gain on disposal of discontinued operations	$ 12	$ 56
Earnings from discontinued operations		
Exploration and Production - U.S.	$ -	$ 46
- Canada	25	16
Total Exploration and Production	$ 25	$ 62
Midstream and Marketing - Cal Ven Pipeline	-	13
Corporate & Other - Former Refining and Marketing	-	-
Corporate & Other - Needle Coke Business	10	(1)
Total earnings from discontinued operations	$ 35	$ 74

BUSINESS SEGMENT RESULTS

See note 20 to the consolidated financial statements in Item 1 of this report for additional details on our reportable segments. The following business segment results should be read in conjunction with the historical financial information provided in the consolidated financial statements and accompanying notes in Item 8 of our 2004 10-K, the consolidated results discussed earlier in this Item 2 and the business and properties descriptions in Items 1 and 2 of our 2004 10-K. Our operations are organized in the following business segments:

Exploration and Production

North America - Included in this category are our oil and gas operations in the United States and Canada. Our exploration and production assets in Western Canada are now included as discontinued operations (see notes 6, 11 and 21 to the consolidated financial statements in Item 1 of this report).

Second Quarter Results: Earnings from continuing operations totaled $146 million in the second quarter of 2005 compared to $108 million for the same period a year ago, which was an increase of $38 million. Higher natural gas and liquids prices contributed $90 million in higher earnings in the second quarter of 2005 compared with the same quarter a year ago. The positive impact from higher prices was partially offset by lower natural gas production in the second quarter of 2005 compared with the same period a year ago, which reduced after-tax earnings by approximately $20 million. United States natural gas production averaged 442 MMcf/d down from 511 MMcf/d in 2004. Most of the natural gas production decline was due to natural field declines primarily in the Gulf of Mexico. The prior year quarter results included a $22 million after-tax gain from the sale of certain of Pure's exploratory mineral fee lands in the United States.

Six Months Results: Earnings from continuing operations totaled $301 million in the first six months of 2005 compared to $221 million for the same period a year ago, which was an increase of $80 million. Higher natural gas and liquids prices contributed $160 million in higher earnings in the first six months of 2005 compared with the same period a year ago. Higher liquids production in the United States increased after-tax earnings by approximately $10 million primarily due to production from deepwater fields in the Gulf of Mexico. The positive impact from higher prices and higher liquids production was partially offset by lower natural gas production in the first six months of 2005 compared with the same period a year ago, which reduced after-tax earnings by approximately $45 million. United States natural gas production averaged 448 MMcf/d down from 512 MMcf/d in 2004. Most of the natural gas production decline was due to natural field declines primarily in the Gulf of Mexico. The first six months of 2004 included the $22 million after-tax gain from the sale of certain of Pure's exploratory mineral fee lands in the United States and a $15 million gain from a litigation settlement related to a previous asset sale.

International - Our International operations encompass oil and gas exploration and production activities outside of North America. Through our International subsidiaries, we operate or participate in production operations in Thailand, Indonesia, Myanmar, Bangladesh, the Netherlands, Azerbaijan and the Democratic Republic of Congo.

Second Quarter Results: Earnings from continuing operations totaled $347 million in the second quarter of 2005 compared to $166 million in the second quarter of 2004. The increase was primarily due to higher liquids and natural gas prices, which increased net earnings by approximately $95 million. In addition, higher production principally from Indonesia, Thailand, Bangladesh and Azerbaijan contributed approximately $70 million to after-tax earnings. International liquids production averaged 102 MBbl/d in the current quarter, up from 81 MBbl/d in the same period a year ago, while natural gas production averaged 1,166 MMcf/d in the second quarter of 2005 up from 922 MMcf/d in the same period a year ago, which was an increase of 26 percent for both liquids and natural gas. Exploration costs in the current quarter were approximately $20 million lower than the second quarter of 2004, primarily due to lower exploration drilling activity in Indonesia and Thailand.

Six Months Results: Earnings from continuing operations totaled $646 million in the first six months of 2005 compared to $341 million in the first six months of 2004. The increase was primarily due to higher liquids and natural gas prices, which increased net earnings by approximately $180 million. In addition, higher production principally from Indonesia, Thailand, Bangladesh and Azerbaijan contributed approximately $100 million to after-tax earnings. International liquids production averaged 99 MBbl/d in the first six months of 2005, up from 84 MBbl/d a year ago, while natural gas production averaged 1,093 MMcf/d up from 913 MMcf/d in the same period a year ago, which was an increase of 18 percent

and 20 percent, respectively. The first six months of 2005 included after-tax gains of $25 million from the sale of miscellaneous oil and gas properties. The first six months of 2005 included foreign exchange related tax benefits and a lower effective tax rate in Thailand, which contributed approximately $30 million to net earnings. Higher DD&A rates attributable primarily to the West Seno production in Indonesia negatively impacted net earnings by approximately $25 million.

Midstream and Marketing

The Midstream and Marketing segment is comprised of our equity interests in certain petroleum pipeline companies in the United States and Argentina, wholly-owned pipelines and terminals throughout the United States, our North America natural gas storage business and the organization that markets the majority of our worldwide liquids production and North American natural gas production. To market our U.S. production, the segment enters into various sale and purchase transactions, including crude oil buy/sell transactions, with unaffiliated oil and gas producing, refining, marketing and trading companies (see crude oil buy/sell discussions in the consolidated financial statements under notes 1 and 2). These transactions effectively transfer the commodities from production locations to industry marketing centers with higher volumes of commercial activity and greater market liquidity. These transactions allow us to better manage our commodity-related risks. Currently, these sale and purchase transactions represent a significant portion of the segment's U.S. crude oil sales and purchases. This marketing organization is also responsible for implementing commodity specific risk management activities on behalf of our exploration and production segment, and it conducts our trading activities involving hydrocarbon derivative instruments.

Second Quarter Results: Earnings from continuing operations totaled $20 million in the current quarter compared to $18 million in the second quarter of 2004. The current period reflects improved results primarily from our pipeline businesses which included a gain on the sale of a domestic pipeline.

The segment's sales and operating revenues were $1.15 billion in the current quarter compared to $1.01 billion in the same quarter a year ago. Included in these totals were sales from marketing activities totaling $935 million in the current quarter compared to $851 million in the same quarter a year ago, representing approximately 43 percent and 47 percent of our total sales and operating revenues for the second quarters of 2005 and 2004, respectively. Sales from marketing activities include buy/sell transactions. The majority of the increase in the segment's sales was primarily due to higher liquids and natural gas prices partially offset by lower marketing volume activity for both liquids and natural gas.

Six Months Results: Earnings from continuing operations totaled $55 million in the first six months of 2005 compared to $41 million in the same period a year ago. The results for the current year reflect improved results from our pipeline and natural gas storage businesses.

The segment's sales and operating revenues were $2.29 billion in the first six months of 2005 compared to $1.99 billion in the same period a year ago. Included in these totals were sales from marketing activities totaling $1.83 billion in the current six month period compared to $1.68 billion in the same period a year ago, representing approximately 44 percent and 48 percent of our total sales and operating revenues for the 2005 and 2004 periods, respectively. Sales from marketing activities include buy/sell transactions. The increase in the segment's sales was due to higher liquids and natural gas prices partially offset by lower marketing volume activity for both liquids and natural gas. In addition, the increase in sales and operating revenues reflected higher sales volumes from our natural gas storage business.

Geothermal

The Geothermal segment includes geothermal steam production for power generation, with operations in the Philippines and Indonesia. Geothermal activities also include the operation of geothermal steam-fired power plants in Indonesia and equity interests in natural gas-fired power plants in Thailand.

Second Quarter Results: Earnings from continuing operations totaled $17 million in the current quarter compared to $57 million in the same period a year ago. The prior year quarter results included a $46 million gain from the settlement of the outstanding contract dispute in our Philippines operations.

Six Months Results: Earnings from continuing operations totaled $34 million in the first six months of 2005 compared to $94 million in the same period a year ago. The 2004 results included the $46 million after-tax gain from the settlement of the outstanding contract dispute in our Philippines operations and a $21 million after-tax gain from the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia. Our Philippines results were higher in the current year, which was attributable to the new contract. In addition, the 2004 results included losses from an equity interest in a natural gas-fired power plant which we sold in 2005.

Corporate and Other

Corporate and Other includes general corporate overhead, miscellaneous operations (including real estate, carbon and mineral businesses), other corporate unallocated costs (including environmental and litigation expenses) and net interest expense.

Second Quarter Results: The results from continuing operations for the current quarter were a loss of $90 million compared to a loss of $82 million in the same period a year ago. Net interest expense for the current quarter was $21 million compared to $33 million in the same quarter a year ago. After-tax expenses for environmental and litigation matters for the current quarter were $27 million compared to $14 million in the same quarter a year ago. The current quarter reflected $6 million after-tax in higher results from our minerals business due primarily to higher margins attributable to molybdenum prices. In the second quarter of 2004, we recorded a provision of $46 million pre-tax ($29 million after-tax) associated with the arbitration ruling regarding Agrium's Kenai, Alaska nitrogen-based fertilizer plant, and our obligations to supply natural gas to the plant. In the current quarter, various tax related adjustments resulted in a charge to tax expense of approximately $10 million. In 2004, we recorded a net tax benefit of $27 million for settlements and assessments with various taxing authorities.

Six Months Results: The results from continuing operations for the first six months of 2005 were a loss of $164 million compared to a loss of $175 million in the same period a year ago. Net interest expense for the first six months of 2005 was $36 compared to $65 million in the same period a year ago. After-tax expenses for environmental and litigation matters for the six months of 2005 were $40 million compared to $35 million after-tax for the same period a year ago. The current year reflected $17 million after-tax in higher results from our minerals business due primarily to higher margins attributable to molybdenum prices. The current year also reflected $15 million in higher employee related expenses. In the current year, various tax related adjustments resulted in a charge to tax expense of approximately $10 million. In the six month period of 2004, we recorded the aforementioned provision of $29 million after-tax associated with the arbitration ruling regarding Agrium's Kenai, Alaska nitrogen-based fertilizer plant and the net tax benefit of $27 million for settlements and assessments with various taxing authorities.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Cash and cash equivalents on hand totaled $1.78 billion at June 30, 2005, up from $1.16 billion at the end of 2004. As previously discussed, we have agreed in our merger agreement with Chevron, among other things, that we will not engage in certain kinds of transactions during the interim period between the execution of the agreement and the consummation of the merger, including limitations on our ability to incur debt, issue securities and sell material assets. If we were to seek to engage in a restricted activity under these covenants, we would be required to obtain the prior consent of Chevron. Based on current commodity prices and current development projects, we do not anticipate that these contractual limitations will materially adversely affect our ability to satisfy our liquidity needs during this interim period and we expect that cash generated from operating activities, routine asset sales and cash on hand will be sufficient in 2005 to cover our operating and capital spending requirements, to make expected dividend payments and to pay down scheduled debt. In addition, we believe that our available borrowing capacity is sufficient to enable us to meet unanticipated cash requirements if needed.

On July 8, 2005, we agreed to sell all of the stock of our Northrock subsidiary in Canada to Pogo for $1.8 billion in cash. We expect to realize after-tax proceeds from the sale of approximately $1.5 billion. The sale, which is subject to customary Canadian regulatory approvals, is expected to close in the third quarter of 2005.

On July 29, 2005, we repaid our $200 million Canadian dollar-denominated term loan which was scheduled to mature in November 2009. The amount repaid translated to $163 million, using the applicable foreign exchange rate.

Cash Flows from Operating Activities

Cash flows from operating activities were $1.63 billion for the six months ended June 30, 2005, compared with $1.13 billion for the same period a year ago. The increase principally reflected the effects of higher worldwide commodity prices.

Capital Expenditures and Other Investing Activities

Capital expenditures were $873 million for the first six months of 2005 compared with $801 million in the same period a year ago. The capital expenditure amounts included $52 million and $63 million in 2005 and 2004, respectively, from our Canadian operation currently held for sale. The current period results reflected $60 million and $25 million in higher expenditures from International and United States operations, respectively.

In the first six months of 2005, capital expenditures included approximately $355 million for the development of undeveloped proved oil and gas reserves, primarily in Thailand and Azerbaijan.

Asset Sales

Pre-tax proceeds from asset sales relating to continuing and discontinued operations were $164 million for the six month period ended June 30, 2005. The current year included pre-tax proceeds of $26 million from the sale of a subsidiary that held our equity interest in an exploration and production company in India. Our Molycorp subsidiary sold down its equity investment in a niobium operation in Brazil, from 40 percent to 35 percent for pre-tax proceeds of $31 million in cash. We sold our needle coke business for $25 million in cash plus $22 million in working capital. We also received pre-tax proceeds of $30 million from the sale of other oil and gas properties, $20 million from the sale of other miscellaneous assets and $10 million from the sale of real estate properties.

Pre-tax proceeds from asset sales were $278 million for the six months ended June 30, 2004. We received net proceeds of $176 million from the sale of certain of our mineral fee lands in the United States, $60 million from the sale of our rights and interests in the Sarulla geothermal project in Indonesia and $19 million from the sale of the Cal Ven Pipeline system in Canada. We also received approximately another $23 million from the sale of various properties, primarily in the Gulf of Mexico.

Long-term Debt

Unocal's total consolidated debt, including current maturities, was $2.54 billion at June 30, 2005, compared with $3.06 billion at the end of 2004. In the first six months of 2005, we paid a combination of cash and Unocal common stock to retire the $242 million outstanding balance of the 6-1/4% convertible junior subordinated debentures (see note 15 for further detail). We retired $85 million in 7.20 percent notes that matured in the first six months of 2005. We paid $77 million as full payment under the revolving portion of our Canadian dollar-denominated credit agreement, which we terminated in July 2005. In addition, we paid $76 million in medium term notes that matured in the first six months of 2005. Finally, we paid $26 million related to a limited recourse loan for our West Seno project in Indonesia and $9 million related to a non-recourse loan from one of our Geothermal segment subsidiaries.

Other Financing Activities

In 2005, we received $120 million from the issuance of 3,555,676 shares of our common stock related to the exercise of existing stock options. This compared to $94 million from the issuance of 3,986,394 shares for the six months ended June 30, 2004.

Off-Balance Sheet Arrangements - Sales of Accounts Receivables

Through a bankruptcy remote wholly-owned subsidiary, Unocal Receivables Corporation ("URC"), we had a sales agreement with an outside unrelated party that provided for the sale of up to $125 million of an undivided interest in domestic crude oil and natural gas trade receivables. We used this program as a low cost and readily available source of working capital. Details of this arrangement are provided in note 11 to the consolidated financial statements in Item 8 of our 2004 10-K. We terminated this program effective April 15, 2005.

Environmental Matters

We are committed to operating our business in a manner that is environmentally responsible. This commitment is fundamental to our core values. As part of this commitment, we have procedures in place to audit and monitor our environmental performance. In addition, we have implemented programs to identify and address environmental risks throughout our company.

Probable costs associated with identified and reasonably estimable environmental obligations have been accrued in a reserve for such obligations. Accruals are based on developments to date, our estimates of the outcomes of these matters and our experience in addressing these 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 our future results of operations, financial condition or liquidity. At June 30, 2005, our reserves for environmental remediation obligations totaled $239 million, of which $112 million was included in current liabilities. During the first six months of 2005, cash payments of $48 million were applied against the reserves and $43 million was added to the reserves. We may also incur additional liabilities 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, we estimate that we could incur possible additional remediation costs aggregating approximately $235 million.

The reserve amounts and estimated possible additional costs are grouped into the following four categories:

Millions of dollars	At June 30, 2005 Reserve	Possible Additional Costs
Superfund and similar sites	$ 12	$ 15
Active Company facilities	25	35
Company facilities sold with retained liabilities and former Company-operated sites	100	80
Inactive or closed Company facilities	102	105
Total	$ 239	$ 235

See notes 16 and 17 to the consolidated financial statements in Item 1 of this report for additional information on environmental related matters.

In the first six months of 2005, we recorded provisions of $25 million for the "Company facilities sold with retained liabilities and former Company-operated sites" category. These provisions were primarily for sites that may have been contaminated by our former operations. The provisions were based on new and revised cost estimates that we identified during 2005 for the remediation of approximately 125 service station, bulk plant and terminal sites and for the assessment and remediation of oil and gas fields in Central California.

During the first six months of 2005, we recorded provisions of $15 million for sites in the "Inactive or closed Company facilities" category, primarily for the Guadalupe oil field site on the central California coast. Soil at this site has been contaminated with diluent, a kerosene-like additive used in the field's former operations. The provision includes revised estimated costs for remediation work that is required by the cleanup and abatement order for the site. The required remediation work has become better defined through ongoing and continuing meetings and negotiations with the

regulatory agencies. This work includes studies, operation and maintenance of remedial systems, restoration, and regulatory agency oversight and permitting procedures.

In the first six months of 2005, our estimated possible additional remediation costs increased by $10 million for the "Company facilities sold with retained liabilities and former Company-operated sites" category. This increase was primarily for the cost of remediation that may be needed at oil and gas fields in Central California that we formerly operated.

Our estimated possible additional costs for the "Inactive or closed Company facilities" category of sites increased by $10 million during the first six months of 2005. The increase was primarily for the Guadalupe oil field site. Higher estimated costs for remediation work may be incurred for groundwater monitoring, operation and maintenance of remedial systems, restoration, and regulatory agency oversight and permitting procedures. These revised estimates are based on ongoing and continuing meetings and negotiations with the regulatory agencies.

Litigation and Other Contingencies

We are also subject to contingent liabilities for existing and potential claims, lawsuits and other proceedings and tax and other matters. For a more detailed discussion on these matters, see Item 3 in Part I and note 23 to the consolidated financial statements included in Item 8 of Part II of our 2004 Form 10-K and Item 1 in Part II and note 17 to the interim financial statements included in Item 1 of Part I of this report.

OPERATIONS OUTLOOK

The following operations outlook is based upon our current expectations and beliefs. These statements are subject to a number of known and unknown risks and uncertainties that could cause actual results to differ materially from those described, including our pending merger with Chevron and the effect on us if the merger is not consummated. Please see the cautionary statement under "Forward-Looking Statements" on page iii of this report and the "Risk Factors" in Item 7 of Part II of our 2004 10-K. This outlook discusses our current expectations regarding certain important operational activities for the remainder of 2005 and for other future time periods. It is not intended to be a complete discussion of all future operational activities.

Our profitability will continue to be significantly affected by crude oil and natural gas commodity prices. We expect energy prices to remain volatile for the remainder of 2005 due to a variety of fundamental and market perception factors including variability of the weather on a year-to-year basis, worldwide demand, crude oil and natural gas inventory levels, production quotas set by OPEC, current and future worldwide political instability, worldwide security and other factors. To seek to mitigate some of that volatility, we have secured fixed price "hedges" on portions of our anticipated future natural gas and crude oil production. From July 2005 through December 2006, we have hedge contracts in place equivalent to approximately 35 percent of our anticipated U.S. Lower 48 production. The average hedge prices through 2006 are approximately $59.00 for crude oil and $7.90 for natural gas. In addition, there are also hedges in place from 2007 through mid-2008 ranging from 10 to 20 percent of anticipated U.S. Lower 48 production.

In the first six months of 2005, we initiated production from all five major projects in our 2005 development pipeline - Mad Dog in the deepwater Gulf of Mexico, Phase 1 of the ACG crude oil project in the Azerbaijan sector of the Caspian Sea, the Moulavi Bazar field in Bangladesh, the K-2 field in the deepwater Gulf of Mexico and Phase 2 of the Thailand crude oil project.

Exploration and Production - North America

United States

- The Mad Dog field in the Gulf of Mexico, operated by BP, began production in January 2005. The K-2 field in the Gulf of Mexico, operated by Eni, began production in May 2005. The estimate of our net production for both the Mad Dog field and K-2 fields combined is expected to average about 5 MBOE/d to 7 MBOE/d in the third quarter of 2005, rising to an average of 8 MBOE/d to 11 MBOE/d in the fourth quarter of 2005. We have a 15.6 percent working interest in the Mad Dog field and a 12.5 percent working interest in the K-2 field.

- Our deepwater Gulf of Mexico exploration and appraisal program continues in 2005. We are currently drilling the Knotty Head well, located in Green Canyon Block 512. We are also currently participating in drilling a well in Green Canyon Block 821, a follow-up on the Puma discovery in Green Canyon Block 823, and Mad Dog Deep, a Paleogene test, in Green Canyon Block 826, both operated by BP.

Canada

- On July 8, 2005, we entered into a Share Purchase Agreement with Pogo to sell all of the outstanding capital stock in our wholly owned Northrock subsidiary in Canada for US$1.8 billion in cash. The transaction, which is subject to customary Canadian regulatory approvals, is expected to close in the third quarter 2005.

Exploration and Production - International

Asia

Thailand:

- Start up of the Phase 2 development of the Thailand crude oil project commenced in June 2005 with production expected to ramp up to peak capacity by late third quarter. The average net production rate from Phase 2 is expected to be between 7 MBOE/d and 9 MBOE/d in the third quarter of 2005 and between 9 MBOE/d and 11 MBOE/d in the fourth quarter of 2005.

- Thailand's electricity market is expected to continue growing in 2005. Additional supplies of natural gas to meet that growth have been constrained by pipeline capacity. De-bottlenecking activities on the two existing pipelines in the Gulf of Thailand should allow us an opportunity for increased production in 2005, prior to the expected completion of a third pipeline in 2006.

Indonesia:

- Development engineering and planning is continuing for multiple oil and gas discoveries in the deepwater Kutei Basin. The development strategy is to install two new deepwater production processing hubs, one at Gendalo and one at Gehem. These hubs will process oil and gas production for multiple satellite developments. The initial plans of development for both hubs are currently being prepared for submission to partners and the Government of Indonesia in 2005.

- We are also continuing to work on our evaluation for development feasibility at the Sadewa field, which is a candidate for early natural gas development because of its proximity to the shelf. Concept selection work has been completed and detailed design work has begun. The development concept is a natural gas and crude oil development from a shallow-water platform with extended reach wells towards targets in deep water.

Bangladesh:

- First production from the Moulavi Bazar field began in March 2005. This new field is expected to increase our net average production over 2004 levels in the country by 14 MBOE/d to 17 MBOE/d in the third quarter of 2005. This production outlook reflects higher volumes due partially to an increase in cost recovery that we expect to receive from the Jalalabad field because of new production from the Moulavi Bazar field. We anticipate the net average incremental production over 2004 levels in the fourth quarter of 2005 to be 9 MBOE/d to 15 MBOE/d due to the completion of cost recovery.

- Work continues to progress at the Bibiyana field which is planned to be developed in stages to provide Bangladesh with natural gas resources in the short, medium and long-term time frames. We currently expect first production by the end of 2006.

Other International

Azerbaijan:

- First production from Phase 1 of the ACG crude oil project began in the first quarter of 2005. Phase 1 is expected to deliver net average production of 11 MBOE/d to 13 MBOE/d in the third quarter of 2005 and 14 MBOE/d to 16 MBOE/d in the fourth quarter of 2005. Chirag will continue to average more than 12 MBOE/d net in the second half of 2005. Development on Phases 2 and 3 of the ACG crude oil project will continue in 2005. We have a 10.28 percent working interest in the AIOC project.

Turkey/Georgia:

- We entered into a farm-in agreement for acreage held by BP in the Turkey and Georgia sections of the Eastern Black Sea. The geologic setting of the exploration acreage is similar to the ACG field in Azerbaijan but at deeper water depths (2100 to 5500 feet). Subject to government approvals, we will acquire a 25 percent working interest in Turkish Block 3534 and a 10 percent working interest in Georgia Blocks APC-IIA, IIB and III. BP plans to spud an exploration well on one of the prospects in Turkey in the third quarter of 2005. We expect our share of capital expenditures for the Black Sea venture to be approximately $50 million in 2005.

Midstream and Marketing

In parallel with the ACG crude oil project, the BTC crude oil pipeline will start to line-fill portions of the pipeline through Georgia and Turkey in the second half of 2005. The BTC pipeline will transport the crude oil from the ACG crude oil project to the Turkish port of Ceyhan and will have a capacity of 1 million Bbl/d. Our interest in this pipeline is 8.9 percent.

FUTURE ACCOUNTING CHANGES

See note 2 to the consolidated financial statements for information about recent accounting pronouncements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to market risks, which may give rise to losses from adverse changes in market prices and rates. The primary market risks to which we are exposed are: (1) commodity prices, (2) interest rates and (3) foreign currency exchange rates.

As part of our overall risk management strategies, we use derivative financial instruments to manage and seek to reduce risks associated with these factors. We also trade hydrocarbon derivative instruments, such as futures contracts, swaps and options to exploit anticipated opportunities arising from commodity price fluctuations. To the extent that we engage in hedging activities to seek to protect ourselves from commodity price volatility, we may be prevented from realizing the benefits of price increases above the levels of the hedges. In addition, speculative trading in hydrocarbon commodities and derivative instruments in connection with our risk management activities subjects us to additional risk.

We determine the fair values of our 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 we feel that current exchange quotes and assumptions regarding interest rates and volatilities are appropriate factors to measure the fair value of our longer termed derivative instruments, other pricing assumptions or methodologies may lead to materially different results in some instances.

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

We use a variance-covariance value at risk model to assess the market risk of our hydrocarbon derivatives. Value at risk represents the potential loss in fair value we would experience on our hydrocarbon derivatives, as a result of commodity price changes using calculated volatilities and correlations over a specified time period with a given confidence level. Our 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 our fixed price pre-paid crude oil and pre-paid natural gas sales. The model also includes our net interests in our subsidiaries' crude oil and natural gas hydrocarbon derivatives and forward sales contracts. Based upon our risk model, the value at risk related to hydrocarbon derivatives held for hedging purposes was $11 million at June 30, 2005. Value at risk related to hydrocarbon derivatives held for non-hedging purposes was immaterial at June 30, 2005. See "Hydrocarbon Derivatives Tables."

Interest Rate Risk - From time to time, we temporarily invest our excess cash in short-term interest-bearing securities issued by high-quality issuers. Our 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 us. Our primary market risk exposure to changes in interest rates relates to our long-term debt obligations. We manage our exposure to changing interest rates principally with 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.

We evaluated the potential effect that near term changes in interest rates would have had on the fair value of our interest rate risk sensitive financial instruments at June 30, 2005. Assuming a ten percent decrease in our weighted average borrowing costs at June 30, 2005, the potential increase in the fair value of our debt obligations and associated interest rate derivative instruments, including the debt obligations and associated interest rate derivative instruments of our subsidiaries, would have been $83 million at June 30, 2005.

Foreign Exchange Rate Risk - We conduct business in various parts of the world and in various foreign currencies. To limit our foreign currency exchange rate risk related to operating income, foreign sales agreements generally contain price provisions designed to insulate our 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, we are 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. Our Canadian subsidiaries are paid in Canadian dollars for their crude oil and natural gas sales.

From time to time, we may purchase foreign currency options or enter into foreign currency swap or foreign currency forward contracts to limit the exposure related to our foreign currency debt or other obligations. At June 30, 2005, we had various foreign currency forward contracts outstanding related to operations in Thailand. We evaluated the effect that near term changes in foreign exchange rates would have had on the fair value of our combined foreign currency position related to our outstanding foreign currency swaps, forward contracts and foreign-currency denominated debt. Assuming an adverse change of ten percent in foreign exchange rates at June 30, 2005, the potential decrease in fair value of the foreign currency swaps, foreign currency forward contracts and foreign-currency denominated debt for us would have been $25 million at June 30, 2005.

Hydrocarbon Derivatives Tables - The following tables set forth the future volumes and price ranges of hydrocarbon derivatives we held at June 30, 2005, along with the fair values of those instruments.

Open Hydrocarbon Hedging Derivative Instruments (a)

	2005	2006	2007	Thereaft
Natural Gas Futures Positions				
Volume (MMBtu)	170,000	-	-	
Average price, per MMBtu	$ 6.65			
Volume (MMBtu)	(8,830,000)	-	-	
Average price, per MMBtu	$ 7.14			
Natural Gas Swap Positions				
Pay fixed price				
Volume (MMBtu)	6,206,900	9,508,000	7,218,000	7,241,00
Average swap price, per MMBtu	$ 4.13	$ 3.46	$ 2.47	$ 2.5
Receive fixed price				
Volume (MMBtu)	5,340,000	-	-	
Average swap price, per MMBtu	$ 6.29			
Natural Gas Basis Swap Positions				
Volume (MMBtu)	1,220,000	-	-	
Average price received, per MMBtu	$ 6.59			
Average price paid, per MMBtu	$ 6.44			
Crude Oil Futures Positions				
Volume (Bbls)	70,000	-	-	
Average price, per Bbl	$ 56.05			
Volume (Bbls)	(1,648,000)	-	-	
Average price, per Bbl	$ 52.72			

Open Hydrocarbon Non-Hedging Derivative Instruments (a)

	2005	2006	2007
Natural Gas Futures Positions			
Volume (MMBtu)	1,760,000	-	300,000
Average price, per MMBtu	$ 7.13		$ 7.77
Volume (MMBtu)	(1,560,000)	-	-
Average price, per MMBtu	$ 7.02		
Natural Gas Swap Positions			
Pay fixed price			
Volume (MMBtu)	2,705,000	-	300,000
Average swap price, per MMBtu	$ 7.01		$ 7.76
Receive fixed price			
Volume (MMBtu)	1,852,500	-	600,000
Average swap price, per MMBtu	$ 6.90		$ 7.74
Natural Gas Spread Swap Positions			
Volume (MMBtu)	24,970,000	7,225,000	-
Average price paid, per MMBtu	$ 0.46	$ 0.72	-
Volume (MMBtu)	25,120,000	7,835,000	900,000
Average price received, per MMBtu	$ 0.46	$ 0.77	$ 1.26
Natural Gas Option (Listed & OTC)			
Call Volume -Buy-(MMBtu)	5,500,000	-	-
Average Call price	$ 7.97		
Call Volume -Sell-(MMBtu)	7,320,000	-	-
Average Call price	$ 7.92		
Put Volume -Buy-(MMBtu)	1,480,000	1,860,000	-
Average Put Price	$ 5.49	4.75	
Put Volume -Sell-(MMBtu)	6,280,000	1,860,000	-
Average Put Price	$ 4.71	$ 4.75	
Crude Oil Futures Positions			
Volume (Bbls)	4,340,000	275,000	-
Average price, per Bbl	$ 49.92	$ 53.87	
Volume (Bbls)	(4,040,000)	(275,000)	-
Average price, per Bbl	$ 49.06	$ 52.09	
Crude Oil Option (Listed & OTC)			
Call Volumes -Sell-(Bbls)	-	-	-
Average price, per Bbl			
Put Volume -Buy-(Bbls)	-	-	-
Average price, per Bbl			
Put Volume -Sell-(Bbls)	-	-	-
Average price, per Bbl			
Crude Oil Swap Positions			
Pay fixed price			
Volume (Bbls)	2,860,000	375,000	-

Average swap price, per Bbl	$ 34.33	$ 39.29	
Receive fixed price			
Volume (Bbls)	3,210,000	475,000	-
Average swap price, per Bbl	$ 33.26	$ 37.30	

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our reports under the Securities Exchange Act of 1934 is processed, recorded, summarized and reported within the time periods specified in the SEC's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by SEC Rule 13a-15(b), we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on the foregoing, our Chief Executive Officer and Chief Financial Officer concluded, as of that time, that our disclosure controls and procedures were effective at the reasonable assurance level.

Internal Control over Financial Reporting

There was no change in our internal control over financial reporting that occurred during the three months ended June 30, 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control processes from time to time in the future.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

See the information with respect to certain legal proceedings pending or threatened against Unocal previously reported in Item 3 of our 2004 10-K and in Item 1 of Part II of our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2005. The following is incorporated by reference: the information regarding the environmental remediation reserve and possible additional remediation costs in notes 16 and 17 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 17 to the consolidated financial statements in Item 1 of Part I of this report.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Unocal Purchases of Equity Securities

The following table shows information regarding repurchases we made of our shares of common stock during the second quarter of 2005:

Period	Total Number of shares Purchased (1)	Avg Price Paid per share	Total # of shares Purchased as Part of Publicly Announced Plans or Programs	Maximum # of Shares That May Yet Be Purchased Under the Plans or Programs
April 1 through April 30, 2005	21,950	$58.00	None	
May 1 through May 31, 2005	10,611	$54.92	None	(2) (3)
June 1 through June 30, 2005	18,036	$62.32	None	
Total	50,597	$58.89	None	

1. During the second quarter, we cancelled 7,951 shares repurchased for the payment of withholding taxes due on restricted stock that vested under various employee restricted stock plans.

   During the second quarter, we purchased 42,646 shares in the open market and distributed these shares to employee participants in Unocal's savings plans, which are defined contribution plans with 401(k) features.

2. At June 30, 2005, the total authorized common stock repurchase program limit authorized by our board of directors was $459 million. There is no expiration date to this repurchase program. No purchases are currently planned under this program.

3. In 2004, our board of directors authorized the repurchase from time to time of shares of our common stock in order to offset the net number of shares of common stock issued by us upon the exercise or granting, as the case may be, of existing or subsequently issued stock options or shares of our restricted common stock. There is no expiration date to the repurchase program. The board authorized management to determine whether, and when, to effect any repurchases under this program and did not limit the aggregate dollar amount for any such repurchases. No purchases are currently planned under this program.

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

Our 2005 annual meeting of stockholders was held on May 23, 2005. The following actions were taken by our stockholders at the annual meeting, for which proxies were solicited pursuant to Regulation 14 under the Securities Exchange Act of

1934:

1. The four nominees proposed by our board of directors were elected as directors by the following votes for three-year terms expiring at the 2008 annual meeting of stockholders, or until their successors are duly elected and qualified or their earlier resignation, if applicable:

Name	Votes For	Votes Withheld
Craig Arnold	235,858,287	7,019,783
James W. Crownover	235,981,853	6,896,217
Donald B. Rice	235,583,875	7,294,195
Mark A. Suwyn	235,879,608	6,998,462

2. A proposal to ratify the appointment of PricewaterhouseCoopers LLP as Unocal's independent auditors for 2005 was passed by a vote of 238,759,878 for (98.34%) versus 2,456,889 against (1.01%) and 1,571,304 abstentions (0.65%). There were 90,000 broker non-votes.

3. A stockholder proposal requiring that the Chairman of the Board be an independent director who has not previously served as an executive officer of Unocal failed to pass, with a vote of 23,550,182 for (11.29%) versus 182,821,266 against (87.66%) and 2,216,143 abstentions (1.05%). There were 34,290,479 broker non-votes.

ITEM 6. EXHIBITS.

The following exhibits are filed or furnished, as applicable, as part of this report:

2.1 Amendment No. 1 to the Agreement and Plan of Merger, dated as of July 19, 2005, among Unocal Corporation, Chevron Corporation and Blue Merger Sub Inc. (incorporated by reference to Exhibit 2.1 to Unocal's Current Report on Form 8-K dated July 19, 2005, and filed July 22, 2005, File No. 1-8483).

2.2 Waiver Letter from Chevron Corporation, dated June 23, 2005 (incorporated by reference to Exhibit 99.2 to Unocal's Current Report on Form 8-K dated June 23, 2005, and filed June 24, 2005, File No. 1-8483).

10.1 Share Purchase Agreement dated July 8, 2005 between Unocal Canada Limited, Unocal Canada Alberta Hub Limited, Unocal Corporation, Pogo Canada, ULC and Pogo Producing Company (incorporated by reference to Exhibit 10.1 to Unocal's Current Report on Form 8-K dated July 12, 2005, and filed July 14, 2005, File No. 1-8483).

10.2 Unocal Deferred Compensation Plan of 2005 (incorporated by reference to Exhibit 10.1 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483).

10.3 2004 Directors' Deferred Compensation and Restricted Stock Unit Award Plan (as amended and restated effective as of January 1, 2005) (incorporated by reference to Exhibit 10.2 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483).

10.4 Unocal Nonqualified Retirement Plan A1 (as amended and restated effective July 14, 2005) (incorporated by reference to Exhibit 10.3 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483).

10.5 Unocal Nonqualified Retirement Plan B1 (as amended and restated effective July 14, 2005) (incorporated by reference to Exhibit 10.4 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483).

10.6 Unocal Nonqualified Retirement Plan C1 (as amended and restated effective July 14, 2005) (incorporated by reference to Exhibit 10.5 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483).

31.1 Chief Executive Officer certifications pursuant to Exchange Act Rule 13a-14(a).

31.2 Chief Financial Officer certifications pursuant to Exchange Act Rule 13a-14(a).

32 Furnished Certifications Pursuant to Exchange Act Rule 13a-14(b).

Copies of exhibits will be furnished upon request. Requests should be addressed to the Corporate Secretary and mailed to the address set forth on the cover page to this report.

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 4, 2005

By: /s/JOHN A. BRIFFETT

John A. Briffett
Vice President and Comptroller
(Duly Authorized Officer and
Principal Accounting Officer)