UNOCAL CORP
Form 10-Q
November 05, 2004

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

FORM 10-Q

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

For the quarterly period ended September 30, 2004

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 October 29, 2004: 263,181,376

UNOCAL CORPORATION

TABLE OF CONTENTS

GLOSSARY

Below are definitions of certain key 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 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 oil and natural gas amounts using a standard measurement. Gas volumes are converted to barrels of oil equivalent on the basis of energy content, where the volume of natural gas that when burned produces the same amount of heat as a barrel of oil (6,000 cubic feet of gas equals one barrel of oil equivalent).

- British Thermal Units ("Btu") is a standardized unit of measure for energy, equivalent to the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. Ten thousand MMBtu (million Btu) is the standard volume for exchange traded 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 natural gas reservoir to a depth of a stratigraphic horizon known to be productive.

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

- Economic interest method pursuant to production sharing contracts is a method by which 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 natural gas reserves that is not a development well.

- Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who 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 oil field. Produced fluids from platform based and subsea completion wells are brought by flowlines to the vessel where they are separated, treated, stored and then offloaded to another vessel for transportation.

- Gross acres or gross wells are the total acres or wells in which 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.

- 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, act as contractor, bear all 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 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 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. Normally, 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 is the percentage of ownership we have in a joint venture, partnership, consortium, project or acreage.

- 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 report contains forward-looking statements. All statements other than historical facts are forward-looking. These statements may be identified by words such as "expects," "anticipates," "intends," "plans," "believes," "estimates," "forecasts," "could," "will" and words of similar meaning, and include statements regarding:

- exploratory drilling, project development and other plans and objectives for future operations,
- oil and gas production rates, timing and growth,
- operating and capital expenditures,
- negotiations, sales and transactions with third parties,
- the availability of cash on hand, borrowings and cash from asset sales and financings to fund our activities,
- possible contingent payments pursuant to completed transactions,
- future tax refunds,
- commodity prices,
- the amount and timing of contingent liabilities for environmental, litigation and tax matters, under guarantees and indemnities and under our benefit and medical plans,
- economic conditions,
- the impact of new or existing accounting pronouncements, and
- repurchases of our common stock from time to time.

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:

- volatility in commodity prices,
- our ability to find or acquire commercially productive oil and gas reservoirs and to develop and produce deepwater fields and other complex projects in a timely and cost-effective manner,
- local demand, infrastructure and the distance to markets for our hydrocarbon

production,
- the accuracy of our estimates and judgments regarding hydrocarbon resources and formations,
- decline rates of producing properties,
- adverse geological and other operational factors, such as formation irregularities, equipment failures or shortages, fires, blow-outs and weather conditions,
- our success in competing against other energy companies and retaining and attracting qualified personnel,
- future costs for environmental, litigation and other contingent liabilities and those under our benefit and medical plans,
- the extent of our operating cash flow and other capital resources available to fund capital expenditures,
- regulatory factors, such as changes in environmental laws and receipt of required permits and licenses,
- international and domestic political and economic factors,
- other risks associated with our substantial international operations, such as trade barriers, currency fluctuations and restrictions on repatriation of earnings,
- our ability to enter into agreements and transactions on acceptable terms with, and performance by, foreign governmental entities, joint venture partners, independent contractors, equipment suppliers, operators of properties in which we have an interest and other third parties,
- market conditions for our common stock, and
- other factors discussed in our 2003 Annual Report on Form 10-K, as amended, and subsequent reports filed by us with the U.S. Securities and Exchange Commission ("SEC").

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 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 September 30,	
Millions of dollars except per share amounts	2004	2003
Revenues		
Sales and operating revenues	$ 1,961	$ 1,472
Interest, dividends and miscellaneous income	6	(2)
Gain on sales of assets	26	65
Total revenues	1,993	1,535
Costs and other deductions		
Crude oil, natural gas and product purchases	772	447
Operating expense	316	344
Administrative and general expense	35	61
Depreciation, depletion and amortization	248	231

Impairments	28	83
Dry hole costs	12	14
Exploration expense	51	39
Interest expense	40	45
Property and other operating taxes	19	18
Distributions on convertible preferred securities of subsidiary trust	-	8
Total costs and other deductions	1,521	1,290
Earnings from equity investments	31	54
Earnings from continuing operations before income taxes and minority interests	503	299
Income taxes	172	145
Minority interests	2	4
Earnings from continuing operations	329	150
Earnings from discontinued operations (a)	1	2
Cumulative effect of accounting changes (b)	-	-
Net earnings	$ 330	$ 152
Basic earnings per share of common stock (c)		
Continuing operations	$ 1.25	$ 0.58
Discontinued operations	0.01	0.01
Cumulative effect of accounting changes	-	-
Net earnings	$ 1.26	$ 0.59
Diluted earnings per share of common stock (d)		
Continuing operations	$ 1.22	$ 0.57
Discontinued operations	0.01	0.01
Cumulative effect of accounting changes	-	-
Net earnings	$ 1.23	$ 0.58
Cash dividends declared per share of common stock	$ 0.20	$ 0.20
(a) Net of tax (benefit)	$ -	$ 2
(b) Net of tax (benefit)	$ -	$ -
(c) Basic weighted average shares outstanding (in thousands)	262,628	258,525
(d) Diluted weighted average shares outstanding (in thousands)	274,287	272,691

See Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

Millions of dollars	At September 30, 2004 (a)
Assets	
Current assets	
Cash and cash equivalents	$ 780
Accounts and notes receivable - net	1,369

Inventories	198
Deferred income taxes	99
Other current assets	33
Total current assets	2,479
Investments and long-term receivables - net	827
Properties - net (b)	8,639
Goodwill	133
Deferred income taxes	272
Other assets	170
Total assets	$ 12,520
Liabilities and Stockholders' Equity	
Current liabilities	
Accounts payable	$ 1,126
Taxes payable	355
Dividends payable	53
Interest payable	49
Current portion of environmental liabilities	106
Current portion of long-term debt and capital leases	235
Other current liabilities	239
Total current liabilities	2,163
Long-term debt and capital leases	2,842
Deferred income taxes	737
Accrued abandonment, restoration and environmental liabilities	891
Other deferred credits and liabilities	1,016
Minority interests	37
Commitments and contingencies - Note 17	
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	-
Common stock ($1 par value, shares authorized: 750,000,000 (c))	278
Capital in excess of par value	1,229
Unearned portion of restricted stock issued	(25)
Retained earnings	4,237
Accumulated other comprehensive income	(301)
Notes receivable - key employees	(3)
Treasury stock - at cost (d)	(581)
Total stockholders' equity	4,834
Total liabilities and stockholders' equity	$ 12,520

(a) Unaudited

(b) Net of accumulated depreciation, depletion and amortization of:	$ 12,387
(c) Number of shares outstanding (in thousands)	262,527
(d) Number of shares (in thousands)	15,292

See Notes to the Consolidated Financial Statements.

-2-

CONSOLIDATED CASH FLOWS (UNAUDITED)

For
End

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	7
Impairments	
Dry hole costs	
Amortization of exploratory leasehold costs	
Deferred income taxes	
Gain on sales of assets	(1
Gain on disposal of discontinued operations	(
Pension expense net of contributions	(
Restructuring provisions net of payments	(
Cumulative effect of accounting changes	
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)	(1,2
Proceeds from sales of assets	2
Proceeds from sales of discontinued operations	1
Return of capital from affiliate company	
Net cash used in investing activities	(7
Cash Flows from Financing Activities	
Long-term borrowings	1
Reduction of long-term debt and capital lease obligations	(2
Minority interests	
Repurchases of common stock	(1
Repurchases of preferred securities	(2
Proceeds from issuance of common stock	1
Dividends paid on common stock	(1
Loans to key employees	
Other	
Net cash used in financing activities	(5
Net increase in cash and cash equivalents	3
Cash and cash equivalents at beginning of year	4
Cash and cash equivalents at end of period	$ 7
Supplemental disclosure of cash flow information:	
Cash paid during the period for:	
Interest (net of amount capitalized)	$ 1
Income taxes (net of refunds)	$ 4

See Notes to the Consolidated Financial Statements.

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 presentation of 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 2003 Annual Report on Form 10-K, as amended.

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. Investments in entities without a controlling interest are generally accounted for by the equity method. 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. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. We follow the successful efforts method of accounting for our oil and gas activities.

Results for the nine months ended September 30, 2004, are not necessarily indicative of future financial results.

We made changes in the reporting of our segments from the reporting utilized in the 2003 Annual Report on Form 10-K, as amended (see note 22 - Segment Data). The financial statements of the prior periods have been reclassified to conform to the 2004 presentation.

2. Accounting Changes

SFAS No. 132 (revised 2003): In 2003, we adopted Statement of Financial Accounting Standards ("SFAS") No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits (revised 2003)." In accordance with this pronouncement, beginning in 2004, quarterly reports include disclosure of the components of net pension and postretirement benefit cost as well as the changes in the estimated current year contributions to the plans. In addition, benefit payment information will be included in our 2004 Annual Report on Form 10-K.

FASB Interpretation No. 46 (revised December 2003): Effective January 1, 2004, we adopted Financial Accounting Standards Board ("FASB") Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities" which clarifies the definition of a variable interest entity and provides a scope exception for certain entities that meet the Statement's definition of a "business." This pronouncement resulted in the deconsolidation of Unocal Capital Trust (the "Trust") (see note 15 for further details). As a result, the $522 million obligation for the Trust's convertible preferred securities was removed from the consolidated balance sheet and replaced by an increase in long-term debt for the $538 million in 6-1/4% convertible junior subordinated debentures of Unocal payable to the Trust. We also recorded a $16 million investment in the Trust on the consolidated balance sheet. The deconsolidation did not affect our consolidated net earnings. In the third quarter of 2004, we redeemed $269 million of the debentures and reduced our investment in the Trust by $8 million (see note 15 - Variable Interest Entities).

FASB Staff Position No. 142-2: In September 2004, the FASB issued Staff Position No. 142-2, "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil- and Gas-Producing Entities," that clarifies that oil and gas drilling rights are tangible assets. This position is consistent with our classification of the cost of acquiring oil and gas drilling rights in property, plant and equipment on our consolidated balance sheet. Therefore, adoption of this rule had no impact on either our earnings or consolidated balance sheet.

FASB Staff Position No. 106-2: In December 2003, "The Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the "Act") was enacted, which introduces a prescription drug benefit under Medicare Part D. The availability of the new drug benefit could cause Medicare eligible plan participants to leave their current employer-sponsored plans (or cause employees to join such plans), depending on the drug benefits provided under those plans relative to the benefits provided by Medicare. The Act also provides that a non-taxable federal subsidy will be paid to sponsors of postretirement benefit plans that provide retirees with a drug benefit that is at least "actuarially equivalent" to the Medicare Part D benefit. The federal subsidy is not payable to a plan sponsor for retirees who leave their current employer-sponsored plan to participate in the Medicare drug program. As of January 1, 2004, the Act's subsidy reduced the Accumulated Postretirement Benefit Obligation ("APBO") of our U.S. Postretirement Welfare plan by $72 million, which will be amortized to future earnings as an actuarial experience gain. In accordance with FASB Staff Position No.106-2, in the third quarter of 2004, we recorded a benefit of $8 million representing 75 percent of the estimated full year impact of the subsidy. This amount consisted of $3 million for the reduction in interest cost, $4 million for amortization of the actuarial gain and $1 million for the reduction in service cost. These amounts are subject to future revision because final detailed regulations specifying the manner in which actuarial equivalency must be determined and the evidence required to demonstrate it are not yet available.

EITF Issue 03-1: "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," is effective with the 2004 Form 10-K and requires additional disclosures for cost method investments. This consensus reached by the FASB's Emerging Issues Task Force ("EITF") also provides recognition and measurement guidance regarding impairment of cost method investments. Adoption of this pronouncement is not expected to have an impact on either our earnings or consolidated balance sheet.

EITF Issue 03-16: "Accounting for Investments in Limited Liability Companies ("LLCs")," is effective beginning with the third quarter 2004. This pronouncement may cause some entities to be accounted for by the equity method rather than on a cost basis. Adoption of this pronouncement did not have an impact on either our earnings or consolidated balance sheet in the third quarter of 2004.

EITF Issue 04-9: 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 major project can commence. EITF Issue 04-9 "Accounting for Suspended Well Costs," seeks 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 at the EITF's September 2004 meeting 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.

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, changes in the carryback and carryforward utilization periods for foreign tax credits and a dividend received deduction with respect to accumulated income earned abroad. The new law could potentially have an impact on our effective tax rate, future taxable income and cash and tax planning strategies, amongst other affects. We are currently in the process of evaluating the impact that the Act will have on our financial position and results of operations.

3. Other Financial Information

o Revenues - During the third quarters of 2004 and 2003, approximately 25 percent and 20 percent, respectively, of total sales and operating revenues were attributable to the resale of liquids and natural gas purchased from others in connection with marketing activities. For the nine months ended September 30, 2004 and 2003, these percentages were approximately 26 percent and 23 percent, respectively. Related purchase costs are classified as expense in the crude oil, natural gas and product purchases category on the consolidated earnings statement.

o Capitalized Interest - During the third quarters of 2004 and 2003, capitalized interest totaled $18 million and $11 million, respectively. For the nine months ended September 30, 2004 and 2003, capitalized interest totaled $44 million and $46 million, respectively. The slight decrease in the nine month period of 2004 as compared to the same period a year ago was primarily due to lower capitalized interest from the West Seno development project in Indonesia that was mostly offset by higher capitalized interest from the Azerbaijan International Operating Company ("AIOC") project in Azerbaijan and the Mad Dog project in the Gulf of Mexico.

o Exploration Expense - Our exploration expense on the consolidated earnings statement consisted of the following:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Millions of dollars	2004	2003	2004	2003
Exploration operations	$ 19	$ 13	$ 55	$ 44
Geological and geophysical	15	7	39	41
Amortization of exploratory leasehold costs	14	17	47	88
Leasehold rentals	3	2	8	9

Exploration expense	$ 51	$ 39	$ 149	$ 182

Amortization of exploratory leasehold costs for the nine month period of 2004 was lower than the comparable period of 2003, which included a $26 million pre-tax provision resulting from our decision to relinquish 44 deepwater Gulf of Mexico blocks before the end of their lease term. The remaining decrease in the amortization of exploratory leasehold costs for the nine month period of 2004 is principally due to lower amortization levels for the Gulf of Mexico compared to a year ago.

4. Dispositions Of Assets

Certain asset sales are discussed below:

In the third quarter of 2004, we sold our 50 percent equity interest in a jointly held project company that owned UnoPaso Exploracao e Producao de Petroleo e Gas Ltda., a Brazilian exploration and production venture, for $67 million in cash plus possible future payments that are contingent on attainment of certain natural gas prices and/or volume thresholds. The underlying assets sold represented net production of approximately 4.5 MBOE/d and were our remaining oil and natural gas assets in Brazil. We recorded an after-tax gain of $1 million.

In the third quarter of 2004, we sold non-oil and gas property in Parachute, Colorado for $26 million in cash. We recorded an after-tax gain of $16 million in the quarter.

Our subsidiary, Pure Resources Inc. ("Pure"), sold certain of its mineral fee lands it held in several states to Black Stone Minerals Company, LP. The sale involved Pure's royalty interests, overriding royalty interests and minor working interests. The $190 million sale price included approximately $75 million for the prospective portion of these mineral fee lands resulting in a $22 million after-tax gain that was recorded in the second quarter of 2004. The net proceeds received were $176 million after sale price adjustments to reflect the effective date of the transaction as October 1, 2003. The sale of the producing portion of these lands was recorded in discontinued operations (see note 8 for further detail).

Our subsidiary, Unocal North Sumatra Geothermal, Ltd. ("UNSG"), received about $60 million from PT PLN (Persero) ("PLN"), the state electricity utility, for the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia. PLN acquired UNSG's interest in the Joint Operation Contract with Pertamina, the Indonesian national petroleum company and the Energy Sales Contract with PLN. We recorded a $21 million after-tax gain from the sale in the first quarter of 2004.

5. Impairment of Assets

As part of our assessment, we review our developed and undeveloped oil and gas properties and other long-lived assets for possible impairment. In the nine month period of 2004, we recorded pre-tax impairment charges of $42 million. Approximately $20 million was attributable to oil and gas fields in the U.S., the majority of which related to impairments of warehouse stock for the Gulf of Mexico region, which was mostly recorded in the third quarter of 2004.
In addition, we recorded an impairment of approximately $11 million relating to our equity investment in a gas-fired power-plant project in the third quarter of

2004 and impairments of $5 million relating to our equity investment in an LPG terminal in East China. In the nine month period of 2003, we recorded pre-tax impairment charges of $86 million, most of which was recorded in the third quarter of 2003. Pre-tax impairments of approximately $79 million were related to oil and gas fields in the Gulf of Mexico region. In addition, we recorded an impairment of approximately $5 million pre-tax in 2003 relating to our investment in the Trans-Andean oil pipeline, which transports crude oil from Argentina to Chile.

6. Restructuring

In 2003, we accrued $38 million pre-tax in restructuring charges and adopted a plan for streamlining our organizational structures in order to align them with our portfolio requirements and business needs. These charges represented the costs associated with eliminating 360 positions and were included in administrative and general expense on the consolidated earnings statement in the second, third and fourth quarters of 2003. During the second quarter of 2004, the plan was modified to reflect a reduction of 36 employees involved in the restructuring and the subsequent reversal of $2 million pre-tax in previously recognized costs. At September 30, 2004, 307 of 324 employees in the plan had been terminated. The remaining 17 individuals have been advised of planned termination dates as a result of the plan. The following table reflects the 2004 plan activity. The majority of the remaining liability of $8 million is expected to be paid by the end of 2004.

Millions of dollars (except employees)	Number of Employees	Termination Costs	Training / Out-placement Costs
Liability at December 31, 2003	360	$ 24	$ 2
1st Quarter Payments		7	-
Liability at March 31, 2004		$ 17	$ 2
2nd Quarter adjustments	(36)	(2)	-
2nd Quarter payments		4	1
Liability at June 30, 2004	324	$ 11	$ 1
3rd Quarter payments		4	-
Liability at September 30, 2004	324	$ 7	$ 1

7. Income Taxes

Income taxes on earnings from continuing operations for the third quarter and nine month periods of 2004 were $172 million and $495 million, respectively, compared with $145 million and $442 million for the comparable periods of 2003. The effective income tax rates for the third quarter and nine month periods of 2004 were 34 percent and 36 percent, respectively, compared with 48 percent and 45 percent, for each of the third quarter and nine month periods of 2003, respectively. The overall lower effective tax rates for both the third quarter and nine month periods of 2004, as compared to the same periods a year ago, are due primarily to net tax benefits of $32 million recorded in the third quarter of 2004 and $60 million for the nine month period of 2004 relating primarily to settlements and assessments with various taxing authorities (see note 17 - "Tax Matters" for additional detail) and the tax benefit effect in 2004 of currency related adjustments in Thailand.

8. Discontinued Operations

In June 2004, our Pure subsidiary sold certain of its prospective and producing mineral fee lands in the U.S., which included approximately 2 MBOE/d of production in Mississippi, Arkansas and Alabama (see note 4 for further details). The $190 million sale price included approximately $115 million for the producing portion of these mineral fee lands resulting in an after-tax gain of approximately $44 million. The gain on the producing asset disposal plus normal results of operations prior to the sale have been reported as discontinued operations in the consolidated earnings statement. These properties generated revenues of $12 million and net earnings of approximately $6 million in 2004 up to the sale date in June 2004. For the nine month period of 2003, these properties generated revenues of $18 million and net earnings of approximately $8 million.

We also sold our Cal Ven Pipeline system located in Alberta, Canada, for approximately $19 million in May 2004 and recorded an after-tax gain of approximately $13 million. The gain plus normal results of operations prior to the sale have been reported as discontinued operations in the consolidated earnings statement. The Cal Ven pipeline generated revenues of $1 million and net earnings of approximately $0.4 million in 2004 up to the sale date and revenues of $3 million and net earnings of approximately $1 million in the nine month period of 2003.

In 2003, we recorded an after-tax gain of $8 million related to the 1997 sale of our former West Coast refining, marketing and transportation assets. The sales agreement contained a provision calling for payments to us for price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. This provision of the agreement terminated at the end of 2003.

The following table summarizes the results from these discontinued operations:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Millions of dollars	2004	2003	2004	2003
Revenues	$ -	$ 7	$ 13	$ 21
Total costs and other deductions	-	3	3	6
Earnings from discontinued operations before income taxes	-	4	10	15
Income taxes on discontinued operations	-	2	4	6
Earnings from discontinued operations	-	2	6	9
Gain on disposal of discontinued operations before income taxes	2	-	86	13
Income taxes on disposal of discontinued operations	1	-	29	5
Gain on disposal of discontinued operations	1	-	57	8
Total earnings from discontinued operations	$ 1	$ 2	$ 63	$ 17

9. 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 third quarter and nine month periods ended September 30, 2004 and 2003:

Millions except per share amounts	Earnings (Numerator)	Shares (Denominator)	Per Share Amount
Three months ended September 30, 2004			
Earnings from continuing operations	$ 329	262.6	
Basic EPS			$ 1.25
Effect of dilutive securities			
Options and common stock equivalents		1.5	
	329	264.1	$ 1.25
Interest on convertible debentures payable to trust (after-tax)	6	10.2	
Diluted EPS	$ 335	274.3	$ 1.22
Three months ended September 30, 2003			
Earnings from continuing operations	$ 150	258.5	
Basic EPS			$ 0.58
Effect of dilutive securities			
Options and common stock equivalents		1.9	
	150	260.4	$ 0.58
Distributions on subsidiary trust preferred securities (after-tax)	7	12.3	
Diluted EPS	$ 157	272.7	$ 0.57

Millions except per share amounts	Earnings (Numerator)	Shares (Denominator)	Per Share Amount
Nine months ended September 30, 2004			
Earnings from continuing operations	$ 877	262.8	
Basic EPS			$ 3.34
Effect of dilutive securities			
Options and common stock equivalents		1.9	

	877	264.7	$ 3.31
Interest on convertible debentures payable to trust (after-tax)	20	11.6	
Diluted EPS	$ 897	276.3	$ 3.25
Nine months ended September 30, 2003			
Earnings from continuing operations	$ 529	258.2	
Basic EPS			$ 2.05
Effect of dilutive securities			
Options and common stock equivalents		1.7	
	529	259.9	$ 2.04
Distributions on subsidiary trust preferred securities (after-tax)	21	12.3	
Diluted EPS	$ 550	272.2	$ 2.02

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. For the three month and nine month periods ended September 30, 2004, there were options outstanding to purchase approximately 1.1 million and 1.2 million shares, respectively, of common stock that were excluded from the computation of diluted EPS. In the three month and nine month periods ended September 30, 2003, there were options outstanding to purchase approximately 8.8 million and 9 million shares, respectively, of common stock that were excluded from the computation of diluted EPS.

10. Stock-Based Compensation

Prior to 2003, we applied Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations in accounting for stock-based compensation. Accordingly, stock-based compensation expense recognized in our consolidated earnings included expenses related to various cash incentive plans that were paid to certain employees based upon defined measures of Unocal's common stock price performance and total shareholder return. In addition, the amounts also included expenses related to our Pure subsidiary, which had its own stock-based compensation plans. Under APB Opinion No. 25, stock-based employee compensation cost was not recognized in earnings when stock options granted had an exercise price equal to the market value of the underlying common stock on the date of grant.

Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," prospectively to all employee awards granted, modified, or settled after December 31, 2002. Therefore, the cost related to stock-based employee compensation included in the determination of net earnings for 2004 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	For the Nine

Millions of dollars except per share amounts	Months Ended September 30, 2004	2003	Months Ended September 30, 2004	2003
Net earnings				
As reported	$ 330	$ 152	$ 940	$ 463
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects and minority interests	2	4	9	10
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects and minority interest	(2)	(5)	(11)	(15)
Pro forma net earnings	$ 330	$ 151	$ 938	$ 458
Net earnings per share:				
Basic - as reported	$1.26	$0.59	$3.58	$1.79
Basic - pro forma	$1.26	$0.58	$3.57	$1.78
Diluted - as reported	$1.23	$0.58	$3.48	$1.78
Diluted - pro forma	$1.23	$0.58	$3.47	$1.76

11. Comprehensive Income

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

Millions of dollars	For the Three Months Ended September 30, 2004	2003	For the Nine Months Ended September 30, 2004	2003
Net earnings	$ 330	$ 152	$ 940	$ 463
Change in unrealized holding gain on investments (a)	-	8	-	8
Change in unrealized gain (loss) on hedging instruments (b)	(2)	17	(18)	14
Reclassification adjustment for settled hedging contracts (c)	(15)	5	(12)	16
Unrealized foreign currency translation adjustments	56	2	27	116
Minimum pension liability adjustment (d)	-	(21)	-	(21)
Total comprehensive income	$ 369	$ 163	$ 937	$ 596
(a) Net of tax effect of:	-	5	-	5
(b) Net of tax effect of:	(1)	10	(11)	8
(c) Net of tax effect of:	(9)	3	(7)	9
(d) Net of tax effect of:	-	12	-	12

12. Assets Held for Sale

In the second quarter of 2004, we sold certain of our prospective mineral fee lands in North America (see note 8 - Discontinued Operations). These lands were held for sale as of December 31, 2003.

In the first quarter of 2004, our UNSG subsidiary sold its rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia (see note 4 - Disposition Of Assets). This property was held for sale as of December 31, 2003.

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 nine month periods ending September 30, 2004 and September 30, 2003 were:

	For the Three Months Ended Septemeber 30,			
	Pension Benefits		Other Benefits	
Millions of dollars	2004	2003	2004	2003
Service cost (net of employee contributions)	$ 10	$ 8	$ 1	$ 1
Interest cost	21	21	3	7
Expected return on plan assets	(23)	(22)	-	-
Amortization of:				
Prior service cost	1	2	-	-
Net actuarial (gains) losses	16	17	(1)	3
Curtailment and settlement (gains) losses	-	-	-	-
Net periodic pension and other benefit cost (credit)	$ 25	$ 26	$ 3	$ 11

	For the Nine Months Ended Septemeber 30,			
	Pension Benefits		Other Benefits	
Millions of dollars	2004	2003	2004	2003
Service cost (net of employee contributions)	$ 26	$ 21	$ 3	$ 3
Interest cost	61	57	16	18
Expected return on plan assets	(61)	(59)	-	-
Amortization of:				
Prior service cost	4	5	-	-
Net actuarial (gains) losses	46	47	6	8
Curtailment and settlement (gains) losses	-	3	-	1
Net periodic pension and other benefit cost (credit)	$ 76	$ 74	$ 25	$ 30

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

	Pension Benefits		Other Benefits	
Weighted-average assumptions	2004	2003	2004	2003
Discount rates	6.00%	6.74%	6.00%	6.75%
Rates of salary increases	4.91%	4.93%	4.99%	4.99%
Expected returns on plan assets	8.00%	8.40%	N/A	N/A

In December 2003, "The Medicare Prescription Drug, Improvement and Modernization Act of 2003" was enacted. As of January 1, 2004, the Act's non-taxable federal subsidy reduced the Accumulated Postretirement Benefit Obligation ("APBO") of our U.S. Postretirement Welfare plan by $72 million, which will be amortized to future earnings as an actuarial gain. In keeping with the guidance provided by FASB Staff Position 106-2, we recorded a benefit of $8 million in the third quarter of 2004, representing 75 percent of the estimated full year impact of the subsidy. This amount consisted of $3 million for the reduction in interest cost, $4 million for amortization of the actuarial experience gain and $1 million for the reduction in service cost.

We are not required under existing funding or tax regulations to make any cash contributions to our U.S. Qualified Retirement Plan in 2004; however, we did make a voluntary $100 million pre-tax contribution to our U.S. Qualified Retirement Plan on July 29, 2004.

We disclosed in our financial statements for the year ended December 31, 2003 that we expected to contribute approximately $48 million in support of our various postemployment benefit plans. This amount consists of $4 million to our Supplemental Executive Retirement plans, approximately $17 million to our foreign pension plans and approximately $27 million to our worldwide postretirement medical plans in 2004. As of September 30, 2004, we anticipate that actual contributions in support of our worldwide post employment benefit plans (exclusive of the aforementioned $100 million contribution to our U.S. Qualified Retirement Plan) in 2004 will not vary materially from the levels forecasted at year-end 2003.

14. Long Term Debt

Unocal's total consolidated debt, including current maturities, was $3.08 billion at September 30, 2004, compared with $2.88 billion at the end of 2003. The increase primarily reflects the recognition of $538 million in 6-1/4% convertible junior subordinated debentures, payable to the Trust, as long term debt, replacing the $522 million convertible preferred securities of the Trust. In the third quarter of 2004, we paid the Trust to redeem half of its convertible preferred securities, which reduced our outstanding balance on the 6-1/4% convertible junior subordinated debentures to $269 million (see note 2 and note 15 for further detail).

During the nine month period of 2004, we also retired $173 million in 6.375% notes and paid down $20 million of medium-term notes, which matured during the period. In addition, we retired the remaining $24 million limited recourse loan balance under the Azerbaijan International Operating Company's Early Oil Project in 2004. We also made a $15 million principal payment on the variable rate portion of the Overseas Private Investment Corporation ("OPIC") Financing Agreement for the West Seno project in Indonesia, which is scheduled to mature in June 2009.

These decreases were partially offset by $40 million in new borrowings related to Phase 1 development of the Azeri-Chirag-Gunashli structure in the Azerbaijan sector of the Caspian Sea, scheduled for repayment semiannually from June 2006 through December 2015 and $95 million drawn under two new loans from the OPIC Financing Agreement, both limited recourse loans, for the first phase of the West Seno project in Indonesia. One loan was drawn for $50 million and the other was drawn for $45 million, and they each carry fixed rates of 3.61% and 4.78%, respectively. Principal payments on the $50 million loan are scheduled semiannually from June 2005 to December 2007, and on the $45 million loan payments are scheduled from June 2005 to June 2008.

A capital lease of $30 million was also added during the second quarter of 2004 for a 10-year lease agreement on a floating storage unit for our Thailand production operations. The lease agreement has an extension option for an additional 5 years.

15. Variable Interest Entities

In 1996, Unocal exchanged 10,437,873 newly issued 6-1/4% trust convertible preferred securities of Unocal Capital Trust, a Delaware statutory trust, for shares of a then-outstanding issue of convertible preferred stock. Unocal acquired the convertible preferred securities, which had an aggregate liquidation value of $522 million, from the Trust, together with 322,821 common securities of the Trust, which had an aggregate liquidation value of $16 million, in exchange for $538 million principal amount of 6-1/4% convertible junior subordinated debentures of Unocal. The Trust was accounted for as a 100-percent-owned consolidated finance subsidiary of Unocal, with the debentures and payments thereon by Unocal to the Trust eliminated in the consolidated financial statements. The trust convertible preferred securities have been fully and unconditionally guaranteed by Unocal in accordance with the terms of Unocal's guarantee agreement.

Pursuant to FASB Interpretation No. 46 "Consolidation of Variable Interest Entities" as revised in December 2003 (see note 2 for further details), we deconsolidated the Trust in the first quarter of 2004. As a result, the $522 million obligation for the convertible preferred securities was removed from the consolidated balance sheet and replaced by $538 million in 6-1/4% convertible junior subordinated debentures of Unocal payable to the Trust. In addition, we recorded our $16 million investment in the Trust in investments and long-term receivables-net on the consolidated balance sheet. Effective in the first quarter of 2004, interest payments on the debentures are now recorded as interest expense on the consolidated earnings statement. In prior periods, payments to the holders of the preferred securities were reported as a separate line item on the consolidated earnings statement. Payments are subject to deferral under certain circumstances. If payments are deferred, Unocal would be prohibited from paying dividends on its common stock during the deferral period.

In the third quarter of 2004, the Trust called 5,218,452, or approximately half, of its outstanding convertible preferred securities. Holders converted 304,150 preferred securities into Unocal common stock and the remaining 4,914,302 convertible preferred securities were redeemed for $246 million, plus a $3 million premium. In connection with this redemption program, Unocal redeemed $269 million of its convertible junior subordinated debentures held by the Trust using cash on hand and by issuing $15 million in Unocal common stock. The Trust utilized the cash it received from Unocal to redeem the 4,914,302 preferred securities and to retire 152,016 of the Trust's common securities which Unocal held as an investment. The Trust now holds $269 million of Unocal's convertible junior subordinated debentures and Unocal holds 170,805 common securities of the Trust, approximating an $8 million investment.

16. Accrued Abandonment, Restoration and Environmental Liabilities

At September 30, 2004, we had accrued $745 million in estimated abandonment and restoration costs as liabilities. At December 31, 2003, we had accrued $710 million in estimated abandonment and restoration costs. The increase in the liability account from December 31, 2003 was due to $33 million in accrued pre-tax accretion expense, $10 million in revisions to existing estimates and $12 million in new abandonment liabilities recorded during the period. Abandonment liability settlements totaled $20 million during the nine month period of 2004.

Our reserve for environmental remediation obligations at September 30, 2004 totaled $252 million, of which $106 million was included in current liabilities. This compared with $252 million at December 31, 2003, of which $118 million was included in current liabilities.

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 September 30, 2004, we had accrued $252 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 $225 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 nine month period ended September 30, 2004, cash payments of $63 million were applied against the reserves and $63 million was added to the reserves. Possible additional remediation costs increased by $20 million during the nine month period of 2004. The accrued costs and the estimated possible additional costs are shown below for four categories of sites:

	At September 30, 2004	
Millions of dollars	Reserve	Estimated Possible Additional Costs
Superfund and similar sites	$ 15	$ 15
Active Company facilities	31	35
Company facilities sold with retained liabilities and former Company-operated sites	97	80

Inactive or closed Company facilities	109	95
Total	$ 252	$ 225

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 categories. 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 September 30, 2004, we have received notifications from the U.S. Environmental Protection Agency ("EPA") that we may be a PRP at 23 sites and may share certain liabilities at these sites. Of the total, four sites are under investigation and/or litigation, and our potential liability is not presently determinable; and for two sites, our potential liability appears to be de minimis. Of the remaining 17 sites, where we have concluded that liability is probable and to the extent costs can be reasonably estimated, a reserve of $11 million has been established for future remediation and settlement costs.

Various state agencies and private parties had identified 22 other similar PRP sites. Five 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 14 sites, a reserve of $4 million has been established for future remediation and settlement costs.

The sites discussed above exclude 128 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 $31 million for estimated future costs of remedial orders, corrective actions and other investigation, remediation and monitoring obligations at certain operating facilities and producing oil and gas fields. We recorded provisions of $9 million during the nine month period of 2004. The provisions were primarily for the estimated additional costs of the remedial investigation and feasibility study (RI/FS) that is continuing at a molybdenum mine located in Questa, New Mexico, which is owned by our Molycorp, Inc. ("Molycorp") subsidiary. The estimated additional costs are based on an evaluation that Molycorp performed in the second quarter of 2004 of the remaining work that will be required to complete the RI/FS. Molycorp has been conducting the RI/FS cooperatively with the U.S. Environmental Protection Agency to determine what, if any, adverse impacts past mining operations may have had on the environment. During the nine month period of 2004, we made payments of $6 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:

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

In each sale, we retained a contractual remediation or indemnification obligation and are responsible only for certain environmental problems that resulted from operations prior to the sale. The reserve represents estimated future costs for remediation work: identified prior to the sale of these sites; included in negotiated agreements with the buyers of these sites where 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 $97 million for this group of sites. During the nine month period of 2004, provisions of $42 million for this category were recorded. These provisions were primarily for approximately 225 sites where we had operated service stations, bulk plants or terminals. The provisions were based on new and revised cost estimates that were developed for these sites in the nine month period of 2004. The provisions were also for new and revised cost estimates for the assessment and remediation of oil fields in Michigan and California. We will perform assessments on areas within these fields to determine if they have been contaminated by our former operations. We have determined that other areas within these sites are contaminated and will require cleanup. Payments of $44 million were made during the nine month period of 2004 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:

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

A reserve of $109 million has been established for these types of facilities. During the nine month period of 2004, we accrued $11 million related to sites in this category primarily for the Beaumont Refinery site and for a former terminal site in Edmonds, Washington. A provision was recorded for the updated cost estimates to close impoundments used in our former operations at the Beaumont, Texas site. In the first quarter of 2004, final design work and related detailed cost estimates to close these impoundments were completed. We also received final approval of a permit for these projects from the Texas Commission on Environmental Quality. The reserve for this category of sites was also increased for the estimated cost of cleanup work at a shutdown terminal in Edmonds, Washington. The cost includes the implementation and operation of a system to remediate petroleum hydrocarbon contamination caused by our former petroleum products storage and transportation operation at the facility. Payments of $12 million were made during the nine month period of 2004 for sites in this category.

Legal Compliance

We are subject to federal, state and local environmental laws and regulations, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), as amended, the Resource Conservation and Recovery Act ("RCRA") and laws governing low level radioactive materials. Under these laws, 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 inactive Guadalupe oil field. As previously discussed, remediation reserves for these sites are included in the "Inactive or closed Company facilities" category and totaled $92 million at September 30, 2004. 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 $63 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

Agrium Litigation: In June 2002, a lawsuit was filed against us by Agrium Inc., a Canadian corporation, and Agrium U.S. Inc., its U. S. subsidiary, in the Superior Court of the State of California for the County of Los Angeles (Agrium U.S. Inc. and Agrium Inc. v. Union Oil Company of California, Case No. BC275407) (the "Agrium Claim"). Simultaneously, we filed suit against the Agrium entities ("Agrium") in the U.S. District Court for the Central District of California (Union Oil Company of California v. Agrium, Inc., Case No. 02-04518 NM) (the

"Company Claim"). We subsequently removed the Agrium Claim to the U.S. District Court for the Central District of California (Case No. 02-04769 NM). The federal court remanded the Agrium Claim to the California Superior Court. In addition, we initiated arbitration concerning the Gas Purchase and Sale Agreement ("GPSA") between us and Agrium U.S. Inc. (AAA Case No. 70 198 00539 02) (the "Arbitration").

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

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

In September 2002, Agrium amended its complaint to add allegations that we breached certain conditions of the September 2000 closing, breached certain indemnification obligations, and violated the pertinent health and safety code. Agrium also asked for recission of the sale of the fertilizer plant, in addition, or as an alternative, to money damages. In addition, Agrium sought a declaration by the arbitration panel that has been convened (see below) that natural gas from Unocal's Ninilchik, Happy Valley fields in South Kenai "or elsewhere" should be delivered to the plant to meet Unocal's alleged obligations under the GPSA.

In the Company Claim, we seek declaratory relief in our favor against the allegations of Agrium set forth above and for judgment on the Retained Earnout in the amount of $17 million plus interest accrued subsequent to May 2002. Unocal also sought reimbursement of over $5 million in royalties paid to the State of Alaska.

The GPSA contains a contractual limit on liquidated damages of $25 million per year, not to exceed a total of $50 million over the life of the agreement. In addition, the PSA contains a limit on damages of $50 million.

On July 16, 2003, the court approved an agreed stipulation between the parties to submit all issues under the GPSA to arbitration. The arbitration proceedings commenced May 24, 2004. The arbitration panel issued its ruling on July 22, 2004. The arbitration panel agreed with us that the GPSA is a reserves-based contract. The panel's decision laid out the methodology for determining past and future gas delivery quantities and for calculating liquidated damages arising from underdeliveries of gas by us to the fertilizer plant. Using the methodology, the arbitration panel found we owed Agrium $36 million through April 2004 plus $2 million in interest through the arbitration ruling date for underdelivery of natural gas to the fertilizer plant. Based on current delivery projections from certain dedicated fields, we expect to reach the GPSA $50 million cap for liquidated damages by the end of 2004 for underdeliveries subsequent to April 2004.

The arbitration panel did not rule on the enforceability of this $50 million cap because its award did not exceed the amount of the cap. The parties continue to disagree over the cap's enforceability. The arbitration panel also ordered Agrium to reimburse us $5 million for excess royalties that have been paid by us to the state of Alaska. We paid Agrium $36 million plus $2 million in interest in September 2004.

The litigation related to the PSA remains pending in California Superior Court in Los Angeles County. We believe we have a meritorious defense to each of the Agrium remaining claims, but that in any event our exposure to damages for all disputes under the agreements is limited by those agreements. Agrium alleges that it is entitled to recover damages in excess of those amounts. Trial has been set for May 18, 2005.

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

Consistent with worldwide industry contracting practice, there was no provision in the PSC for compensating the Bangladesh government or Petrobangla for resources lost during the contractor's operations. Even if some form of compensation were due, Unocal and OBL believe that settlement compensation for the blowout was fully addressed in a 1998 Supplemental Agreement to the PSC (the "Supplemental Agreement"), which, among other matters, waived OBL's then 50-percent contractor's share (as well as the then 50-percent contractor's share held by our Unocal Bangladesh, Ltd., subsidiary ("Unocal Bangladesh")) of entitlement to the recovery of costs incurred in the drilling of the MB #1 and the blowout, waived their right to invoke force majeure in connection with the blowout, and reduced by five percentage points their contractors' profit share (with a concomitant increase in Petrobangla's profit share) of future production from the sands encountered by the MB #1 well to a drill depth of 840 meters or, if the blowout sand reservoir were not present or development is not feasible deemed commercial, from other commercial fields in the Moulavi Bazar "ring-fenced" area of Block 14. Consequently, Unocal and OBL consider the matter closed and Unocal Blocks 13 and 14 Ltd. has advised Petrobangla that no additional compensation is warranted. By Writ Petition Affidavit dated March 24, 2003, a concerned citizen filed suit in the Bangladesh lower court (Alam v. Bangladesh, Petrobangla, Department of Environment, and Unocal Bangladesh, Ltd., Supreme Court of Bangladesh, High Court Division, Writ Petition No. 2461 of 2003) on the basis of the MB #1 blowout. We were notified of the suit on May 26, 2003 when we received the court's order to show cause why the Supplemental Agreement should not be declared illegal and cancelled on account of its having been executed without lawful authority, and why Unocal Bangladesh should not be directed to stop exploration until it compensates for the MB# 1 blowout. No hearing is currently scheduled on the matter, and we believe the action is not well founded.

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 has 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 have received a cash refund of $33 million in October 2004 and expect to receive approximately another $30 million by the end of the year, representing overpaid taxes plus interest thereon. An additional refund is anticipated in the first quarter of 2005. Taxable years 1979-1984 are now closed and barred from additional assessment of federal income taxes. Although the IRS has completed its audit of Unocal for taxable years 1985-1994 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 completed. Accordingly, the IRS refers to the 1985-1994 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 has been 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 completed. 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.

With respect to state tax matters, a tentative settlement has been reached with the Franchise Tax Board of the state of California with respect to taxable years 1989-1991. We have received cash refunds of $20 million in October 2004 and anticipate receiving at least another $27 million by the end of the year, representing overpaid taxes plus interest thereon.

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 September 30, 2004, the reserve for this category totaled $97 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-Tbilisi-Ceyhan ("BTC") 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 September 30, 2004, 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 approximately $15 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 September 30, 2004, we had obtained various surety bonds for $180 million. These surety bonds included a bond for $69 million securing our performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of gas over a ten-year period that began in January of 1999 and will end in December of 2008 and $111 million in various other routine performance bonds held by local, city, state and federal agencies. We also had obtained $87 million in standby letters of credit at September 30, 2004, of which $29 million represented letters of credit with the revenue department in Thailand relating to a tax appeal, $20 million represented a letter of credit for margin requirements for gas purchases in Canada and $14 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 $525 million. Approximately $134 million of the $525 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 $300 million of the $525 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 $150 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 $226,000. The future remaining minimum lease payment obligation was approximately $80 million at September 30, 2004. 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. Capital Stock

Treasury Stock: In the third quarter of 2004, we purchased 4,130,000 common shares at a cost of $150 million. This tranche of the stock repurchase program was originally approved in January 1998 when our Board of Directors extended the repurchase program of common stock by $200 million, adding to the $400 million of common stock it had authorized for repurchase in 1996.

In February 2004, we repurchased 539,208 shares of our common stock from four of the original participants of the Executive Stock Purchase Program (the "Program") of 2000 at market prices. The purchases, which aggregated to approximately $20 million, were accounted for as treasury stock on the consolidated balance sheet. The recipients used the proceeds to repay the loans made by Unocal for the original acquisition of the shares (see note 19 for further detail).

At September 30, 2004, we held 15,291,992 common shares as treasury stock at a cost of $581 million. At December 31, 2003, we held 10,622,784 common shares at a cost of $411 million.

19. Loans to Certain Officers and Key Employees

In February 2004, we repurchased 539,208 shares from four of the original participants in our 2000 Executive Stock Purchase Program at market price for approximately $20 million. The purchase of this number of shares was approved by our board of directors in February 2004. The Program was approved by our board of directors and by our stockholders at the annual stockholders meeting in May 2000. The balance of the loans under this Program, including accrued interest, totaled $3 million at September 30, 2004 and $27 million at December 31, 2003, and was reflected as a reduction to stockholders' equity on the consolidated balance sheet.

20. 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 September 30, 2004, we had approximately $21 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 September 30, 2004, we had no material 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. We reported a gain of $1 million in the nine month period of 2004 due to ineffectiveness for cash flow and fair value hedges. At September 30, 2004, we had approximately $40 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 October 2004 through December 2005. Nearly 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 were $3.37 billion at September 30, 2004. Fair values were based on the discounted amounts of future cash outflows using the rates offered to us for debt with similar remaining maturities.

21. 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.

As a result of adopting FASB Interpretation No. 46 (revised December 2003) (see note 2 and 15 for further detail), we deconsolidated Unocal Capital Trust effective January 1, 2004.

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. The 2003 tables also present the Trust, as part of the condensed consolidating financial information.

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

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elimina
Revenues				
Sales and operating revenues	$ -	$ 389	$ 1,850	$ (
Interest, dividends and miscellaneous income	-	1	7	
Gain on sales of assets	-	24	2	
Total revenues	-	414	1,859	(
Costs and other deductions				
Purchases, operating and other expenses	4	299	1,168	(
Depreciation, depletion and amortization	-	65	183	
Impairments	-	12	16	
Dry hole costs	-	3	9	
Interest expense	11	22	9	
Total costs and other deductions	15	401	1,385	(
Equity in earnings of subsidiaries	341	310	-	(
Earnings from equity investments	-	1	30	
Earnings from continuing operations before income taxes and minority interests	326	324	504	(
Income taxes	(4)	(17)	193	
Minority interests	-	-	2	
Earnings from continuing operations	330	341	309	(
Earnings from discontinued operations	-	-	1	
Net earnings	$ 330	$ 341	$ 310	$ (

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the Three Months Ended September 30, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elim
Revenues					
Sales and operating revenues	$ -	$ -	$ 339	$ 1,307	
Interest, dividends and miscellaneous income	-	8	(3)	-	

Gain on sales of assets	-	-	15	42
Total revenues	-	8	351	1,349
Costs and other deductions				
Purchases, operating and other expenses	4	-	254	815
Depreciation, depletion and amortization	-	-	61	170
Impairments	-	-	14	69
Dry hole costs	-	-	5	9
Interest expense	8	-	38	8
Distributions on convertible preferred securities	-	8	-	-
Total costs and other deductions	12	8	372	1,071
Equity in earnings of subsidiaries	161	-	189	-
Earnings from equity investments	-	-	(1)	55
Earnings from continuing operations before income taxes and minority interests	149	-	167	333
Income taxes	(3)	-	6	142
Minority interests	-	-	-	4
Earnings from continuing operations	152	-	161	187
Earnings from discontinued operations	-	-	-	2
Net earnings	$ 152	$ -	$ 161	$ 189

-24-

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the Nine Months Ended September 30, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elimina
Revenues				
Sales and operating revenues	$ -	$ 1,033	$ 5,393	$ (
Interest, dividends and miscellaneous income	1	6	34	
Gain on sales of assets	-	8	102	
Total revenues	1	1,047	5,529	(
Costs and other deductions				
Purchases, operating and other expenses	9	820	3,506	(
Depreciation, depletion and amortization	-	193	527	
Impairments	-	18	24	
Dry hole costs	-	30	47	
Interest expense	28	79	25	
Distributions on convertible preferred securities	-	-	-	
Total costs and other deductions	37	1,140	4,129	(
Equity in earnings of subsidiaries	969	991	-	(1,
Earnings from equity investments	-	4	103	

Earnings from continuing operations before

income taxes and minority interests	933	902	1,503	(1,
Income taxes	(7)	(69)	571	
Minority interests		-	6	
Earnings from continuing operations	940	971	926	(1,
Earnings from discontinued operations	-	(2)	65	
Net earnings	$ 940	$ 969	$ 991	$ (1,

CONDENSED CONSOLIDATED EARNINGS STATEMENT
For the Nine Months Ended September 30, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elim
Revenues					
Sales and operating revenues	$ -	$ -	$ 1,212	$ 4,508	
Interest, dividends and miscellaneous income	-	25	15	6	
Gain on sales of assets	-	-	49	58	
Total revenues	-	25	1,276	4,572	
Costs and other deductions					
Purchases, operating and other expenses	9	-	877	3,061	
Depreciation, depletion and amortization	-	-	245	499	
Impairments	-	-	17	69	
Dry hole costs	-	-	63	32	
Interest expense	25	1	97	25	
Distributions on convertible preferred securities	-	24	-	-	
Total costs and other deductions	34	25	1,299	3,686	
Equity in earnings of subsidiaries	490	-	594	-	
Earnings from equity investments	-	-	6	144	
Earnings from continuing operations before income taxes and minority interests	456	-	577	1,030	
Income taxes	(7)	-	40	409	
Minority interests	-	-	-	8	
Earnings from continuing operations	463	-	537	613	
Earnings from discontinued operations	-	-	8	9	
Cumulative effects of accounting changes	-	-	(55)	(28)	
Net earnings	$ 463	$ -	$ 490	$ 594	$

CONDENSED CONSOLIDATED BALANCE SHEET

At September 30, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Elimina
Assets				
Current assets				
Cash and cash equivalents	$ -	$ 227	$ 553	
Accounts and notes receivable - net	117	382	987	
Inventories	-	7	269	
Other current assets	-	108	24	
Total current assets	117	724	1,833	
Properties - net	-	1,978	6,664	
Other assets including goodwill	5,761	5,657	2,171	(12
Total assets	$5,878	$ 8,359	$ 10,668	$ (12
Liabilities and Stockholders' Equity				
Current liabilities				
Accounts payable	$ -	$ 326	$ 915	$
Current portion of long-term debt	-	162	73	
Other current liabilities	54	316	434	
Total current liabilities	54	804	1,422	
Long-term debt and capital leases	269	1,648	925	
Deferred income taxes	-	(205)	942	
Accrued abandonment, restoration and environmental liabilities	-	382	509	
Other deferred credits and liabilities	1	672	347	
Minority interests	-	-	24	
Stockholders' equity	5,554	5,058	6,499	(12
Total liabilities and stockholders' equity	$5,878	$ 8,359	$ 10,668	$ (12

-27-

CONDENSED CONSOLIDATED BALANCE SHEET
At December 31, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries
Assets				
Current assets				
Cash and cash equivalents	$ 1	$ -	$ 45	$ 358
Accounts and notes receivable - net	94	-	360	946
Inventories	-	-	15	205
Other current assets	(1)	-	127	28
Total current assets	94	-	547	1,537
Properties - net	-	-	2,012	6,315
Other assets including goodwill	4,645	541	5,433	1,564

Total assets	$4,739	$ 541	$ 7,992	$ 9,416
Liabilities and Stockholders' Equity				
Current liabilities				
Accounts payable	$ -	$ -	$ 335	$ 831
Current portion of long-term debt	-	-	193	55
Other current liabilities	52	3	299	427
Total current liabilities	52	3	827	1,313
Long-term debt	-	-	1,811	824
Deferred income taxes	-	-	(184)	888
Accrued abandonment, restoration and environmental liabilities	-	-	390	454
Other deferred credits and liabilities	-	-	654	309
Minority interests	-	-	-	32
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust holding solely parent debentures	-	522	-	-
Stockholders' equity	4,687	16	4,494	5,596
Total liabilities and stockholders' equity	$4,739	$ 541	$ 7,992	$ 9,416

CONDENSED CONSOLIDATED CASH FLOWS
For the Nine Months Ended September 30, 2004

Millions of dollars	Unocal (Parent)	Union Oil (Parent)	Non-Guarantor Subsidiaries	Eliminatio
Cash Flows from Operating Activities	$ 407	$ 575	$ 710	
Cash Flows from Investing Activities				
Capital expenditures and acquisitions (includes dry hole costs)	-	(262)	(981)	
Proceeds from sales of assets and discontinued operations	-	64	337	
Return of capital from affiliate company	-	-	48	
Net cash used in investing activities	-	(198)	(596)	
Cash Flows from Financing Activities				
Change in long-term debt	-	(193)	83	
Dividends paid on common stock	(158)	-	-	
Minority interests	-	-	(2)	
Proceeds from issuance of common stock	149	-	-	
Repurchases of common stock	(170)	-	-	
Repurchases of preferred securities	(253)	-	-	
Other	24	(2)	-	
Net cash provided by (used in) financing activities	(408)	(195)	81	

Increase (decrease) in cash and cash equivalents	(1)	182	195
Cash and cash equivalents at beginning of period	1	45	358
Cash and cash equivalents at end of period	$ -	$ 227	$ 553

CONDENSED CONSOLIDATED CASH FLOWS
For the Nine Months Ended September 30, 2003

Millions of dollars	Unocal (Parent)	Unocal Capital Trust	Union Oil (Parent)	Non-Guarantor Subsidiaries
Cash Flows from Operating Activities	$ 130	$ -	$ 417	$ 1,106
Cash Flows from Investing Activities				
Capital expenditures and acquisitions (includes dry hole costs)	-	-	(336)	(960
Proceeds from sales of assets and discontinued operations	-	-	150	204
Net cash used in investing activities	-	-	(186)	(756
Cash Flows from Financing Activities				
Change in long-term debt and capital leases	-	-	(114)	112
Dividends paid on common stock	(155)	-	-	-
Minority interests	-	-	-	(257
Proceeds from issuance of common stock	15	-	-	-
Other	10	-	-	(5
Net cash used in financing activities	(130)	-	(114)	(150
Increase in cash and cash equivalents	-	-	117	200
Cash and cash equivalents at beginning of period	-	-	(18)	186
Cash and cash equivalents at end of period	$ -	$ -	$ 99	$ 386

22. Segment Data

We made changes in the reporting of our segments from the reporting utilized in the 2003 Annual Report on Form 10-K, as amended, as detailed in the following tables. 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.

Our Exploration and Production segment has simplified its North America presentation by combining the Alaska business unit with the U.S. Lower 48 business to form the U.S. geographic designation. In the International geographic designation, we now present Asia and Other, instead of the previous categories of Far East and Other. In addition, the former Trade segment has been combined with the Midstream segment to form the Midstream and Marketing segment.

Segment Information For the Three Months Ended September 30, 2004	Exploration and Production North America			International	
Millions of dollars	U.S.	Canada	Total N.A.	Asia	Other
Sales & operating revenues	$ 204	$ 80	$ 284	$ 394	$ 70
Other income (loss) (a)	(2)	-	(2)	2	1
Inter-segment revenues	279	34	313	155	-
Total	481	114	595	551	71
Earnings (loss) from equity investments	-	-	-	11	1
Earnings (loss) from continuing operations	97	15	112	189	31
Earnings from discontinued operations (net)	1	-	1	-	-
Net earnings (loss)	98	15	113	189	31
Assets (at September 30, 2004)	3,164	1,333	4,497	3,574	941

	Midstream and Marketing	Geothermal	Corporate and Ot Admin & General	Net Interest Expense	Envir menta Litiga
Sales & operating revenues	$ 1,096	$ 38	$ -	$ -	$ -
Other income (loss) (a)	2	-	-	3	-
Inter-segment revenues	2	-	-	-	-
Total	1,100	38	-	3	-
Earnings (loss) from equity investments	10	-	-	-	-
Earnings (loss) from continuing operations	12	3	(19)	(26)	(20)
Earnings from discontinued operations (net)	-	-	-	-	-
Net earnings (loss)	12	3	(19)	(26)	(20)
Assets (at September 30, 2004)	1,210	528	-	-	-

Segment Information For the Three Months Ended September 30, 2003	Exploration and Production North America			International	
Millions of dollars	U.S.	Canada	Total N.A.	Asia	Other
Sales & operating revenues	$ 205	$ 39	$ 244	$ 329	$ 49
Other income (loss) (a)	47	12	59	-	1
Inter-segment revenues	248	36	284	67	-
Total	500	87	587	396	50
Earnings (loss) from equity investments	6	-	6	12	1
Earnings (loss) from continuing operations	87	15	102	113	23
Earnings from discontinued operations (net)	1	-	1	-	-
Net earnings (loss)	88	15	103	113	23
Assets (at December 31, 2003)	3,315	1,324	4,639	3,377	765

	Midstream and Marketing	Geothermal	Corporate and Ot Admin & General	Net Interest Expense	Envir menta Litiga
Sales & operating revenues	$ 774	$ 41	$ -	$ -	$ -
Other income (loss) (a)	5	2	-	(4)	-
Inter-segment revenues	2	-	-	-	-
Total	781	43	-	(4)	-
Earnings (loss) from equity investments	18	5	-	-	-
Earnings (loss) from continuing operations	19	19	(21)	(32)	(33)
Earnings from discontinued operations (net)	1	-	-	-	-
Net earnings (loss)	20	19	(21)	(32)	(33)
Assets (at December 31, 2003)	1,097	611	-	-	-

Segment Information For the Nine Months Ended September 30, 2004	Exploration and Production North America			International	
Millions of dollars	U.S.	Canada	Total N.A.	Asia	Other
Sales & operating revenues	$ 699	$ 219	$ 918	$1,102	$ 206

Other income (loss) (a)	43	-	43	4	3
Inter-segment revenues	714	100	814	357	-
Total	1,456	319	1,775	1,463	209
Earnings (loss) from equity investments	-	-	-	33	3
Earnings (loss) from continuing operations	318	43	361	484	77
Earnings from discontinued operations (net)	50	-	50	-	-
Net earnings (loss)	368	43	411	484	77
Assets (at September 30, 2004)	3,164	1,333	4,497	3,574	941

	Midstream and Marketing	Geothermal	Corporate and Ot		
			Admin & General	Net Interest Expense	Envir menta Litiga
Sales & operating revenues	$ 3,080	$ 202	$ -	$ -	$ -
Other income (loss) (a)	10	45	-	13	-
Inter-segment revenues	8	-	-	-	-
Total	3,098	247	-	13	-
Earnings (loss) from equity investments	38	(1)	-	-	-
Earnings (loss) from continuing operations	53	97	(67)	(91)	(47)
Earnings from discontinued operations (net)	13	-	-	-	-
Net earnings (loss)	66	97	(67)	(91)	(47)
Assets (at September 30, 2004)	1,210	528	-	-	-

Segment Information For the Nine Months Ended September 30, 2003	Exploration and Production				
	North America			International	
Millions of dollars	U.S.	Canada	Total N.A.	Asia	Other
Sales & operating revenues	$ 622	$134	$ 756	$ 982	$145
Other income (loss) (a)	96	12	108	-	1
Inter-segment revenues	920	115	1,035	230	-
Total	1,638	261	1,899	1,212	146
Earnings (loss) from equity investments	15	-	15	32	5
Earnings (loss) from continuing operations	310	47	357	371	52

Earnings from discontinued operations (net)	8	-	8	-	-
Cumulative effect of accounting changes (b)	(32)	4	(28)	13	-
Net earnings (loss)	286	51	337	384	52
Assets (at December 31, 2003)	3,315	1,324	4,639	3,377	765

	Midstream and Marketing	Geothermal	Corporate and Ot Admin & General	Net Interest Expense	Envir menta Litiga
Sales & operating revenues	$ 2,700	$104	$ -	$ -	$ -
Other income (loss) (a)	6	4	-	6	-
Inter-segment revenues	7	-	-	-	-
Total	2,713	108	-	6	-
Earnings (loss) from equity investments	51	10	-	-	-
Earnings (loss) from continuing operations	49	38	(66)	(91)	(78)
Earnings from discontinued operations (net)	1	-	-	-	-
Cumulative effect of accounting changes (b)	(2)	-	-	-	-
Net earnings (loss)	48	38	(66)	(91)	(78)
Assets (at December 31, 2003)	1,097	611	-	-	-

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 Unocal's 2003 Annual Report on Form 10-K, as amended, and the consolidated financial statements and related notes therein and Management's Discussion and Analysis in Item 2 of Unocal's 2004 first and second quarterly reports on Form 10-Q and the interim consolidated financial statements and related notes therein. Our 2003 Annual Report on Form 10-K contains a discussion of other matters not included herein, such as disclosures regarding critical accounting policies and estimates and contractual obligations. You should read the following discussion and analysis together with the cautionary statement under "Forward-Looking Statements" on page iii of this report.

We simplified our reporting segments effective January 1, 2004. In our Exploration and Production segment: (1) we combined the Alaska business unit with the U.S. Lower 48 to form the U.S. geographic designation under North America and (2) we now present Asia and Other instead of the previous categories of Far East and Other under International. In addition, the former Trade segment has been combined with the Midstream segment to form the Midstream and Marketing segment. See note 22 to the consolidated financial statements in Item 1 of this report for revisions to our reportable segments.

OVERVIEW

Unocal's 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 Asia and North America. We are also a leading producer of geothermal energy and a provider of electrical power in Asia. Other activities include ownership in proprietary and common carrier pipelines, natural gas storage facilities and the marketing of hydrocarbon commodities. Our strategy is focused on creating value for our stockholders by continuing to advance oil and gas development projects and delivering successful exploration results through the drill bit. 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.

Some of our more significant operational highlights and other activities from the third quarter of 2004 are listed below:

- completed the buyback of $150 million of Unocal common stock, redeemed $269 million of our outstanding 6-1/4% convertible junior subordinated debentures and made a contribution of $100 million to our U.S. qualified pension plan,
- ramp-up of production continued on the deepwater West Seno project in Indonesia, and the field was producing about 39 MBOE/d (gross) at the end of September,
- AIOC participant companies approved and sanctioned Phase 3 development of the Azeri-Chirag-Deepwater Gunashli ("ACG") field in the Azerbaijan sector of the Caspian Sea. Phase 1 and Phase 2 of the project were sanctioned in 2001 and 2002, respectively,
- construction of the Phase 1 and 2 developments of the AIOC project in the Caspian Sea progressed; first oil at the wellhead is expected in early 2005 for Phase 1,
- approximately 85 percent of the construction completed on the Baku-Tbilisi-Ceyhan ("BTC") export pipeline from the Caspian Sea,
- $67 million received in cash from the sale of our 50 percent equity interest in a jointly held project company that owned UnoPaso Exploracao e Producao de Petroleo e Gas Ltda., a Brazilian exploration and production venture that owned our remaining oil and natural gas assets in Brazil; possible future payments contingent on achieving certain natural gas prices and/or volume thresholds,
- deepwater appraisal wells encountered hydrocarbons on the St. Malo prospect in the Gulf of Mexico and on the deepwater Ranggas, Gehem and Gula prospects in Indonesia,
- completed the deepwater Gulf of Mexico Sardinia well as a dry hole but encountered significant porous sandstones,
- completed successful delineation drilling in the South Gomin operating area in the Gulf of Thailand, and
- elected not to proceed with our participation in five contracts to explore for, develop and market natural gas resources in the Xihu Trough off the coast of Shanghai, in the East China Sea.

CONSOLIDATED RESULTS

The following table summarizes our consolidated net earnings for the third quarter and nine month periods ended September 30, 2004 and 2003:

	For the Three Months Ended September 30,	For the Nine Months Ended September 30,

Millions of dollars	2004	2003	2004	2003
Earnings from continuing operations	$ 329	$ 150	$ 877	$ 529
Earnings from discontinued operations	1	2	63	17
Cumulative effect of accounting changes	-	-	-	(83)
Net earnings	$ 330	$ 152	$ 940	$ 463

Earnings From Continuing Operations

Third Quarter Results: Earnings from continuing operations were $329 million in the third quarter of 2004, which was an increase of $179 million compared to the same quarter a year ago. The increase was primarily due to higher realized worldwide liquids and natural gas prices, which increased net earnings by approximately $90 million and $30 million, respectively. In the current quarter, our worldwide average realized liquids price was $38.85 per Bbl, which was an increase of $11.57 per Bbl from the $27.28 per Bbl realized in the same period a year ago. Our hedging program lowered the average realized liquids price by $1.51 per Bbl in the current quarter while the prior year quarter included a loss of 6 cents per Bbl from hedging activities. Our worldwide average realized natural gas price, which included a loss of 3 cents per Mcf from hedging activities in the current quarter, was $3.90 per Mcf. This was an increase of 30 cents per Mcf from the $3.60 per Mcf price realized during the same period a year ago. There was not any effect on natural gas prices from hedging activities in the third quarter of 2003. The results of the third quarter of 2004 reflect a net tax benefit of $32 million relating primarily to settlements and assessments with various taxing authorities and $13 million in higher tax benefits primarily due to currency related adjustments in Thailand. After-tax impairments were approximately $30 million lower in the third quarter of 2004 compared to the same period a year ago. This was primarily due to the impairments in 2003 related to the assets that were held for sale in the Gulf of Mexico, partially offset by an impairment in the third quarter of 2004 of our equity interest investment in a gas-fired power plant and an impairment related to warehouse stock for our Gulf of Mexico operations (see note 5 - Impairment of Assets). Our after-tax environmental and litigation expenses were $21 million in the third quarter of 2004, compared with $38 million in 2003, primarily reflecting lower outside litigation support costs. In addition, the third quarter of 2003 included a $6 million after-tax charge related to our 2003 restructuring plan. International liquids production was higher in the current quarter than the prior year quarter primarily from Indonesia and Thailand, which increased net earnings by approximately $15 million.

These positive variance factors were partially offset by lower North America production, which reduced net earnings by approximately $60 million in the third quarter of 2004 compared with the same period a year ago. The decline in North America production was due primarily to the sale of oil and gas producing assets. The third quarter of 2004 included approximately $17 million in after-tax gains from asset sales, primarily from the sale of non-oil and gas property in Parachute, Colorado, while the third quarter of 2003 included after-tax gains on asset sales of approximately $35 million related primarily to the sale of the majority of our shares in Tom Brown, Inc. ("Tom Brown").

Nine Months Results: Earnings from continuing operations were $877 million in the nine month period of 2004 compared to $529 million for the same period a year ago. The increase was primarily due to higher worldwide liquids and natural gas prices, which increased net earnings by approximately $160 million and $90 million, respectively. In the nine month period of 2004, our worldwide average realized liquids price was $33.85 per Bbl, which was an increase of $6.49 per

Bbl, or 24 percent, from the same period a year ago. Our average realized liquids price included losses from our hedging activities of $1.47 per Bbl in the nine month period of 2004 while the nine month period of 2003 included a loss of 19 cents per Bbl from hedging activities. Our worldwide average realized natural gas price, including a gain of one cent per Mcf from hedging activities, was $3.92 per Mcf in the nine month period of 2004. This was an increase of 24 cents per Mcf, or 7 percent, from the $3.68 per Mcf, including a loss of 11 cents per Mcf from hedging activities, realized during the nine month period of 2003. International liquids production was higher in the nine month period of 2004 compared to the same period a year ago primarily from Indonesia and Thailand, which increased net earnings by

approximately $30 million. Exploration expenses and dry hole costs were lower in the nine month period of 2004 compared with the same period a year ago, primarily due to lower amortization of exploratory leasehold costs and lower drilling activity, increasing net earnings by approximately $35 million. In addition, the nine month period of 2004 included an after-tax gain of $46 million from the settlement of an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines. The nine month period of 2004 reflects net tax benefits of $60 million relating primarily to settlements and assessments with various taxing authorities and $32 million in higher tax benefits primarily due to currency related adjustments in Thailand. After-tax impairments were approximately $24 million lower in the nine month period of 2004 compared to the same period a year ago. This was primarily due to the impairments in 2003 related to the assets that were held for sale in the Gulf of Mexico, partially offset by an impairment of our equity interest investment in a gas-fired power plant and an impairment related to warehouse stock for our Gulf of Mexico operations (see note 5 - Impairment of Assets). After-tax environmental and litigation expenses were $59 million in the nine month period of 2004, compared with $83 million in the same period a year ago. The nine month period of 2004 also included a $1 million after-tax benefit from an adjustment to the 2003 company-wide restructuring plan, for which we recorded charges totaling $23 million in 2003. The nine month period of 2004 included approximately $70 million in after-tax gains from asset sales, primarily from the sale of certain of our exploratory mineral fee lands in the U.S., the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia, the sale of non-oil and gas property in Parachute, Colorado and other miscellaneous real estate properties. The nine month period of 2003 included after-tax gains of approximately $60 million from asset sales, including the sale of all of our stock holding in Matador Petroleum Corporation ("Matador"), the majority of our shares in Tom Brown held at that time and miscellaneous property in Canada.

These positive variance factors were partially offset by lower North America production, which reduced net earnings by approximately $170 million in the nine month period of 2004. We also recorded a provision of $46 million pre-tax ($29 million after-tax) associated with the recent arbitration ruling regarding Agrium's Kenai, Alaska nitrogen-based fertilizer plant, and our obligations to supply natural gas to the plant.

Earnings From Discontinued Operations

Earnings from discontinued operations were $1 million and $2 million in the third quarters of 2004 and 2003, respectively, and $63 million and $17 million for the nine month periods of 2004 and 2003, respectively.

The nine month period of 2004 included approximately $44 million after-tax from our sale of certain mineral fee producing properties in the U.S. and $13 million after-tax from our sale of the Cal Ven pipeline located in Alberta, Canada. The remaining amounts in the nine month period of 2004 reflect after-tax earnings of $6 million from our operations in these mineral fee producing properties and the Cal Ven pipeline prior to sale. After-tax earnings from the mineral fee producing properties and the Cal Ven pipeline were $2 million and $9 million during the third quarter and nine month periods of 2003, respectively.

The nine month period of 2003 included an after-tax gain of $8 million related to the 1997 sale of our former West Coast refining, marketing and transportation assets. The sales agreement contained a provision calling for payments to us for price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. This provision of the agreement terminated at the end of 2003.

Cumulative Effect of Accounting Changes

In the first quarter of 2003, we recorded a non-cash $83 million after-tax charge for the cumulative effect of a change in accounting principle related to the initial adoption of Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations."

Revenues

Revenues from continuing operations for the third quarter of 2004 were $1.99 billion compared with $1.54 billion for the same period a year ago. In the nine month period of 2004, total revenues from continuing operations were $5.86 billion compared with $4.93 billion for the same period a year ago. The increase in both the third quarter and nine month periods primarily reflected higher crude oil and natural gas prices. This was partially offset by lower North America production.

Income Taxes

Income taxes on earnings from continuing operations for the third quarter and nine month periods of 2004 were $172 million and $495 million, respectively, compared with $145 million and $442 million for the comparable periods of 2003. The effective income tax rate for the third quarter and nine month periods of 2004 was 34 percent and 36 percent, respectively, compared with 48 percent and 45 percent, for each of the third quarter and nine month periods of 2003, respectively. The overall lower effective tax rates for both the third quarter and nine month periods of 2004, as compared to the periods a year ago, are due primarily to a net tax benefit of $32 million in the third quarter of 2004 and $60 million for the nine month period of 2004 relating primarily to settlements and assessments with various taxing authorities and the tax benefit effect in 2004 of currency related adjustments in Thailand.

Operating Highlights

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

OPERATING HIGHLIGHTS

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
North America Net Daily Production				

Liquids (thousand barrels)				
U.S. (a)	51	63	54	67
Canada	16	17	16	17
Total liquids	67	80	70	84
Natural gas - dry basis (million cubic feet)				
U.S. (a)	486	644	503	709
Canada	83	90	83	91
Total natural gas	569	734	586	800
North America Average Prices (excluding hedging activities) (b)				
Liquids (per barrel)				
U. S.	$ 40.37	$ 28.41	$ 35.77	$ 28.64
Canada	$ 35.43	$ 24.02	$ 31.22	$ 25.37
Average	$ 39.23	$ 27.47	$ 34.75	$ 27.96
Natural gas (per mcf)				
U. S.	$ 5.13	$ 4.52	$ 5.12	$ 5.03
Canada	$ 5.23	$ 4.96	$ 5.32	$ 5.24
Average	$ 5.14	$ 4.57	$ 5.15	$ 5.05
North America Average Prices (including hedging activities) (b)				
Liquids (per barrel)				
U. S.	$ 35.97	$ 28.27	$ 31.63	$ 28.18
Canada	$ 35.43	$ 24.02	$ 31.22	$ 25.37
Average	$ 35.85	$ 27.36	$ 31.54	$ 27.59
Natural gas (per mcf)				
U. S.	$ 5.06	$ 4.56	$ 5.19	$ 4.78
Canada	$ 5.01	$ 4.64	$ 5.04	$ 4.93
Average	$ 5.05	$ 4.57	$ 5.17	$ 4.79

(a) Includes proportional interests in production of equity investees.
(b) Excludes gains/losses on derivative positions not accounted for as hedges and ineffective portions of hedges.

OPERATING HIGHLIGHTS (CONTINUED)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2004	2003	2004	2003
International Net Daily Production (c)				
Liquids (thousand barrels)				
Asia	70	59	66	58
Other (a)	18	20	19	20
Total liquids	88	79	85	78
Natural gas - dry basis (million cubic feet)				
Asia	927	934	888	956
Other (a)	15	23	24	23
Total natural gas	942	957	912	979
International Average Prices (d)				
Liquids (per barrel)				
Asia	$ 41.04	$ 26.64	$ 35.58	$ 26.92

Other	$ 42.33	$ 29.25	$ 36.63	$ 27.76
Average	$ 41.27	$ 27.20	$ 35.80	$ 27.11
Natural gas (per mcf)				
Asia	$ 3.19	$ 2.86	$ 3.09	$ 2.79
Other	$ 4.21	$ 4.57	$ 4.18	$ 4.45
Average	$ 3.20	$ 2.87	$ 3.10	$ 2.80

Worldwide Net Daily Production (a) (c)				
Liquids (thousand barrels)	155	159	155	162
Natural gas - dry basis (million cubic feet)	1,511	1,691	1,498	1,779
Barrels oil equivalent (thousands)	407	441	405	458
Worldwide Average Prices (excluding hedging activities) (b)				
Liquids (per barrel)	$ 40.36	$ 27.34	$ 35.32	$ 27.55
Natural gas (per mcf)	$ 3.93	$ 3.60	$ 3.91	$ 3.79
Worldwide Average Prices (including hedging activities) (b)				
Liquids (per barrel)	$ 38.85	$ 27.28	$ 33.85	$ 27.36
Natural gas (per mcf)	$ 3.90	$ 3.60	$ 3.92	$ 3.68

(a) Includes proportional interests in production of equity investees.
(b) Excludes gains/losses on derivative positions not accounted for as hedges and ineffective portions of hedges.
(c) International production is presented utilizing the economic interest method.
(d) International did not have any hedging activities.

BUSINESS SEGMENT RESULTS

See note 22 to the consolidated financial statements in Item 1 of this report for an explanation of changes to our reportable segments effective as of January 1, 2004, which are organized as follows:

Exploration and Production

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

North America - Included in this category are the U.S. and Canada oil and gas operations.

Third Quarter Results: After-tax earnings totaled $112 million in the third quarter of 2004 compared to $102 million for the same period a year ago, which was an increase of $10 million. Higher natural gas and liquids prices contributed $50 million in higher earnings in the third quarter of 2004 compared with the quarter a year ago. After-tax impairments were approximately $8 million in the third quarter of 2004 compared to $48 million in the same period a year ago. This decrease was primarily due to the impairments in 2003 related to the assets that were held for sale in the Gulf of Mexico. The positive impact from higher prices and lower impairments was offset by lower natural gas and liquids production in the third quarter of 2004 compared with the same period a year ago, which reduced after-tax earnings by approximately $60 million. North America liquids production averaged 67,000 Bbl/d in the third quarter of 2004, down from 80,000 Bbl/d a year ago, while natural gas production averaged 569 MMcf/d down from 734 MMcf/d in 2003. Most of the production decline was due to the divestiture of various properties in the Gulf of Mexico, onshore U.S. and Canada in 2003. In addition, the third quarter of 2003 included approximately $30 million after-tax in gains on asset sales primarily from the sale of the majority of our shares in Tom Brown.

Nine Months Results: After-tax earnings totaled $361 million in the nine month period of 2004 compared to $357 million for the same period a year ago, which was an increase of $4 million. Higher natural gas and liquids prices increased net earnings by approximately $110 million in the nine month period of 2004 compared with the same period a year ago. In addition, exploration expenses and dry hole costs were lower in the nine month period of 2004 compared with the same period a year ago, primarily due to lower amortization of exploratory leasehold costs and lower drilling activity, which increased net earnings by approximately $50 million. After-tax impairments were approximately $13 million in the nine month period of 2004 compared to $49 million in the same period a year ago. This decrease was primarily due to the impairments in 2003 related to the assets that were held for sale in the Gulf of Mexico. The nine month period of 2004 also included a $15 million litigation settlement related to a previous asset sale.

These positive factors were partially offset by lower natural gas and liquids production in the nine month period of 2004 compared to the same period a year ago, which reduced after-tax earnings by approximately $170 million. North America liquids production averaged 70,000 Bbl/d in the nine month period of 2004, down from 84,000 Bbl/d a year ago, while natural gas production averaged 586 MMcf/d down from 800 MMcf/d for the nine month period a year ago. Most of the production decline was due to the divestiture of various properties in the Gulf of Mexico, onshore U.S. and Canada in 2003. The nine month period of 2004 included approximately $27 million after-tax in asset sale gains, primarily from the sale of certain of our exploratory mineral fee lands in the U.S. The nine month results of 2003 included $55 million after-tax in asset sale gains, primarily from the sale of all of our stock holding in Matador and the majority of our shares in Tom Brown and miscellaneous property in Canada. In addition, the sale of our equity investments in Matador and Tom Brown in 2003 reduced net earnings by $10 million in 2004 as compared to 2003.

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.

Third Quarter Results: After-tax earnings totaled $220 million in the third quarter of 2004 compared to $136 million in the third quarter of 2003. The increase was primarily due to higher liquids and natural gas prices, which increased net earnings by approximately $55 million and $10 million, respectively. In addition, higher production principally from Indonesia and Thailand contributed approximately $15 million to after-tax earnings. The results of the third quarter of 2004 reflect higher net tax benefits of $10 million primarily due to currency related adjustments in Thailand as compared to the same period a year ago. These positive factors were partially offset by a $10 million after-tax charge

for the relinquishment of lands and provision for settlement of obligations related to the termination of our participation in five contracts to explore for, develop and market natural gas resources in the Xihu Trough off the coast of Shanghai, in the East China Sea.

Nine Months Results: After-tax earnings totaled $561 million in the nine month period of 2004 compared to $423 million in the nine month period of 2003. The increase was primarily due to higher liquids and natural gas prices, which increased net earnings by approximately $110 million and $30 million, respectively. Higher liquids production benefited the 2004 results by adding approximately $30 million to net earnings and was primarily due to higher West Seno production in Indonesia. The nine month period of 2004 reflects higher net tax benefits as compared to the same period a year ago, which increased after-tax earnings by approximately $25 million due to currency related adjustments in Thailand. These positive factors were partially offset by lower natural gas production primarily from Myanmar, which reduced after-tax earnings by approximately $15 million. The nine month period of 2004 results reflected higher operating expenses, primarily from Indonesia, as compared to the same period a year ago, which reduced net earnings by $15 million. Higher dry hole costs, primarily from Indonesia and Thailand, in the nine month period of 2004, as compared with the same period a year ago, reduced net earnings by approximately $10 million. In addition, the nine month period of 2004 included the aforementioned $10 million after-tax charge related to the termination of our participation in the exploration and development of the Xihu Trough in China.

Midstream and Marketing

The Midstream and Marketing segment is comprised of our equity interests in certain petroleum pipeline companies, wholly-owned pipelines and terminals throughout the U.S., our North America gas storage business and the organization that markets the majority of our worldwide liquids production and North American natural gas production. In addition, the marketing organization conducts our trading activities involving hydrocarbon derivative instruments, for which hedge accounting is not used, to exploit anticipated opportunities arising from commodity price fluctuations. The marketing organization also purchases limited amounts of physical inventories for energy trading purposes when arbitrage opportunities arise. These commodity risk-management and trading activities are subject to internal restrictions, including value at risk limits, which measure our potential loss from likely changes in market prices.

Third Quarter Results: Earnings from continuing operations totaled $12 million in the current quarter compared to $19 million in the third quarter of 2003. The results for the third quarter of 2004 reflect lower earnings from our pipeline business. The third quarter of 2003 results reflected a gain on the sale of a domestic pipeline asset. The third quarter of 2004 results included a $3 million after-tax write-off related to a project to develop an offshore bulk oil transfer system in the western Gulf of Mexico. The third quarter of 2003 results included a $4 million after-tax in impairment related to our investment in the Trans-Andean oil pipeline, which transports crude oil from Argentina to Chile.

The segment's sales and operating revenues were $1.1 billion in the current quarter compared to $776 million in the same quarter a year ago. Included in these totals were sales from marketing activities totaling $920 million in the current quarter compared to $633 million in the same quarter a year ago, representing approximately 47 percent and 43 percent of our total sales and operating revenues for the third quarters of 2004 and 2003, respectively. The increase in sales from marketing activities was primarily due to higher international and domestic crude oil revenues resulting from higher crude oil prices.

Nine Months Results: Earnings from continuing operations totaled $53 million in the nine month period of 2004 compared to $49 million in the same period a year ago. The higher 2004 results reflect gains from crude oil and natural gas trading activities, which were positively impacted by volatile commodity prices. This was partially offset by lower earnings from our pipelines business. The nine month period of 2003 results included gains on the sale of domestic pipeline assets.

The segment's sales and operating revenues were $3.08 billion in the nine month period of 2004 compared to $2.7 billion in the same period a year ago. Included in these totals were sales from marketing activities totaling $2.6 billion in the current nine month period compared to $2.29 billion in the same period a year ago, representing approximately 54 percent and 48 percent of our total sales and operating revenues for the 2004 and 2003 periods, respectively. The increase in sales from marketing activities was primarily due to higher international and domestic crude oil revenues resulting from higher crude oil prices, which was partially offset by lower domestic natural gas revenues resulting from lower volumes attributable mainly to property sales in 2003.

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 gas-fired power plants in Thailand.

Third Quarter Results: Earnings from continuing operations totaled $3 million in the current quarter compared to $19 million in the same period a year ago. The current period was negatively impacted by lower earnings from our equity interests in certain gas-fired power plants, which included an after-tax impairment of $11 million and foreign exchange losses in the current quarter compared to foreign exchange gains in the prior year quarter.

Nine Months Results: Earnings from continuing operations totaled $97 million in the nine month period of 2004 compared to $38 million in the same period a year ago. The 2004 results included a $46 million gain from the settlement of the outstanding contract dispute in our Philippines operations (see "Philippines Settlement" below for further detail) 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. The remaining increase was primarily due to improved results from our operations at Gunung Salak. The prior year's results reflect lost generation and additional repair costs associated with damage caused by landslides at Gunung Salak. In addition, the nine months results in 2004 reflect lower earnings from our equity interests in certain gas-fired plants as compared to the same period a year ago, primarily due the aforementioned equity investment impairment and foreign exchange losses in 2004 compared to foreign exchange gains in 2003.

Philippines Settlement: Our Unocal Philippines, Inc. ("UPI"), formerly known as Philippines Geothermal, Inc., subsidiary obtained in June 2004 final Philippine government and court approvals of a settlement for past contractual issues covering the ongoing operations of the steam resources at Tiwi and Mak-Ban on the island of Luzon. In July, UPI received $50 million in cash and expects to receive the outstanding settlement amount owed of $25 million by National Power Corporation and Power Sector Assets and Liabilities Management Corporation by the end of the year.

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.

Third Quarter Results: The results for the current quarter were a loss of $18 million compared to a loss of $126 million in the same period a year ago. The third quarter of 2004 results included a net tax benefit of $32 million relating primarily to settlements and assessments with various taxing authorities. The third quarter of 2004 included an after-tax gain of $16 million from the sale of non-oil and gas property in Parachute, Colorado. After-tax expenses for environmental and litigation matters for the current quarter were $21 million compared to $38 million in the same period a year ago. In addition, the current quarter reflected approximately $10 million after-tax in higher results from our minerals business due to higher margins attributable to molybdenum prices and $10 million after-tax in lower pension and retiree medical related expenses. The third quarter of 2003 included a $6 million after-tax charge related to our 2003 restructuring plan.

Nine Months Results: The results for the nine month period of 2004 were a loss of $195 million compared to a loss of $338 million in the same period a year ago. After-tax expenses for environmental and litigation matters for the nine months of 2004 were $57 million compared to $83 million after-tax for the same period a year ago. The nine month period of 2004 included net tax benefits of $60 million relating primarily to settlements and assessments with various taxing authorities. The current year results included 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. The nine month period of 2004 also included an after-tax gain of $16 million from the sale of non-oil and gas property in Parachute, Colorado. In addition, the nine month period reflected approximately $10 million after-tax in higher results from our minerals business due to higher margins attributable to molybdenum prices and $10 million after-tax in lower pension and retiree medical related expenses due primarily to recognition in the third quarter of 2004 of the federal subsidy provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 and the impact of our $100 million contribution to our qualified U.S. pension plan. The nine month period

of 2004 included a $1 million after-tax benefit from the adjustment to the 2003 company-wide restructuring, for which we recorded charges totaling $23 million in 2003.

LIQUIDITY AND CAPITAL RESOURCES

Cash and cash equivalents on hand totaled $780 million at September 30, 2004, up from $404 million at the end of 2003. Based on current commodity prices and current development projects, we expect cash generated from operating activities, asset sales and cash on hand to be sufficient for the remainder of 2004 to cover our operating and capital spending requirements and 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. As of the date of this report, there are no material restrictions imposed by credit agreements or other contracts to which Unocal or its subsidiaries is a party that would restrict inter-company loans, capital contributions, dividends or other distributions of cash among Unocal and its consolidated subsidiaries, equity investees or variable interest entities or otherwise have a material impact on our liquidity.

Cash Flows from Operating Activities

Cash flows from operating activities, including working capital and other changes, were $1.69 billion for the nine month period ended September 30, 2004, compared with $1.65 billion for the same period a year ago. The increase principally reflected the effects of higher worldwide commodity prices. The positive impact from higher prices was partially offset by the contribution of $100 million to our U.S. Qualified Retirement Plan and the negative impact from lower North America production, compared to the same period a year ago. The nine month period of 2004 reflects higher tax payments net of refunds. Refunds included the receipt of $35 million relating to a federal income tax refund for the 2003 tax year and the receipt of payment from the Indonesian government in settlement of disputed value added taxes we paid in prior years.

Asset Sales

Pre-tax proceeds from asset sales relating to continuing and discontinued operations were $401 million for the nine month period ended September 30, 2004. The current year included net proceeds of $176 million from the sale of certain of our mineral fee lands in the U.S., $67 million from the sale of our 50 percent equity interest in a Brazilian exploration and production venture that owned our remaining oil and natural gas assets in Brazil, $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 $31 million from the sale of various oil and gas properties, primarily in the Gulf of Mexico and $48 million from the sale of other miscellaneous and real estate properties including the sale of non-oil and gas property in Parachute, Colorado.

Pre-tax proceeds from asset sales relating to continuing and discontinued operations were $354 million for the nine month period ended September 30, 2003. We received $122 million from the sale of most of our shares in Tom Brown Inc. and $80 million from the sale of our equity interest in Matador. We also completed the sale of various properties in Canada, onshore U.S. and the Gulf of Mexico in the first half of 2003, which netted us approximately $118 million in proceeds. In addition, cash proceeds included $23 million in other miscellaneous property sales and $11 million related to a participation payment which was received from the purchaser of our former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline.

Capital Expenditures and Other Investing Activities

Capital expenditures were $1.24 billion for the nine month period of 2004 compared with $1.3 billion in the same period a year ago. This year's expenditures level primarily reflects lower exploratory capital requirements in the Gulf of Mexico. Last year, capital expenditures in our Midstream and Marketing segment included the BTC pipeline project expenditures prior to its financing by the BTC Pipeline Company. In the nine month period of 2004, capital expenditures included approximately $522 million for the development of undeveloped proved oil and gas reserves, primarily in Indonesia, Azerbaijan, Thailand and the deepwater Gulf of Mexico.

In the nine month period of 2004, cash flows from investing activities included $48 million representing a return of capital from the completion of the BTC financing which closed in February 2004. The BTC Pipeline Company is financing up to 70 percent of the pipeline's cost. We have an 8.9 percent equity interest in the pipeline company.

Long-term Debt

During the nine month period of 2004, we reduced our outstanding balance on the 6-1/4% convertible junior subordinated debentures by $269 million, retired $173 million in 6.375% notes and paid down $20 million of medium-term notes that matured in 2004. In addition, we retired the remaining $24 million limited recourse loan balance under the AIOC Early Oil Project in 2004. We also made a $15 million principal payment on the variable rate portion of the Overseas Private Investment Corporation Financing Agreement for the West Seno project in Indonesia, which is scheduled to mature in June 2009.

These decreases were partially offset by $40 million in new borrowing relating to Phase 1 development of the Azeri-Chirag-Gunashli structure in the Azerbaijan sector of the Caspian Sea, scheduled for repayment semiannually from June 2006 through December 2015 and $95 million drawn under two new loans from the OPIC Financing Agreement, both limited recourse loans, for the first phase of the West Seno project in Indonesia. One loan was drawn for $50 million and the other was drawn for $45 million, and they each carry fixed rates of 3.61% and 4.78%, respectively. Principal payments on the $50 million loan are scheduled semiannually from June 2005 to December 2007, and on the $45 million loan payments are scheduled from June 2005 to June 2008.

Other Financing Activities

In August 2004, we repurchased 4,130,000 shares of our common stock at a cost of approximately $150 million utilizing cash on hand. This repurchase program was announced in July 2004 (see Item 2 of Part 2 for further detail).

Credit Facilities and Other Financing Sources

Revolving Credit Facility

General

In August 2004, our wholly owned subsidiary, Union Oil Company of California, entered into a $1.0 billion revolving credit agreement with a maturity date of August 12, 2009, and terminated its $600 million and $400 million credit facilities. Unocal guaranteed the obligations of Union Oil under the credit agreement. The credit agreement provides for the lenders to make up to $500 million of the $1.0 billion available in the form of letters of credit.

As of September 30, 2004, there were no borrowings outstanding under the credit agreement. Our ability to borrow at any particular time under the credit agreement is subject to the accuracy of certain representations and warranties and the absence of any defaults or events of default that we believe are customary for such a facility.

The following is a summary of certain provisions of our credit agreement. It is not a complete discussion of all provisions or terms of the credit agreement. Please refer to the complete agreement, which we have filed as Exhibit 10 to our Form 8-K dated and filed August 18, 2004.

Interest Rates

The interest rate for any borrowing under the credit agreement is determined at our option as follows:

- Eurodollar loans for specified periods at the applicable LIBO Rate plus an applicable borrowing spread; or
- competitive bid loans provided by any or all of the lenders through a competitive process; or
- a rate established each day as the greater of the prime rate or the federal funds rate plus 1/2%.

Credit Rating Triggers

The applicable rate for Eurodollar revolving loans and the applicable facility fees vary in accordance with Unocal's credit ratings. Lower credit ratings result in higher facility fees and Eurodollar loan rates and higher credit ratings result in lower facility fees and Eurodollar loan rates. The credit agreement does not have drawdown restrictions or prepayment obligations in the event of a credit rating downgrade.

Mandatory Prepayments

The credit agreement provides for termination of the loan commitments and mandatory prepayments of any borrowings, interest and fees under certain specified events, including if (1) any person or group becomes the beneficial owner of more than 30 percent of the then outstanding voting stock of Unocal other than in a transaction having the approval of Unocal's board of directors, at least a majority of which are continuing directors, or (2) if continuing directors cease to constitute at least a majority of Unocal's board of directors.

Negative Covenants

The credit agreement contains financial and other covenants, including covenants that limit our and certain of our subsidiaries' abilities to, among other things:

- incur liens upon any of our existing or future property or assets, other than permitted liens allowed by the credit agreement; and
- exceed a total debt to total capitalization ratio of 0.70 to 1.0 (total capitalization is defined as total debt plus total equity, with the convertible junior subordinated debentures excluded from total debt and included as equity in the ratio calculation).

Events of Default

The credit agreement includes events of default relating to:

- failure to pay amounts due in accordance with the terms of the credit agreement;
- failure to observe or perform any other affirmative covenants or other agreements under the credit agreement that remains uncured for thirty days after receipt of a notice of default;
- failure to observe or perform any negative covenants under the credit agreement;
- accuracy of representations and warranties;
- defaults and accelerations of other material indebtedness or material guarantee obligations;
- bankruptcy, insolvency, reorganization and other similar proceedings and actions;
- certain ERISA matters;
- material non-payment or non-appeal of judgments and decrees;
- failure to own 100 percent of Union Oil or the majority of each borrowing subsidiary; and
- unenforceability of any guarantees under the credit agreement.

The occurrence of an event of default may result in the termination of the loan commitments and require prepayments of any borrowings, interest and fees.

Canadian Credit Facility

We also have a $295 million Canadian dollar-denominated non-revolving credit facility with a variable rate of interest due to terminate on December 19, 2005. At September 30, 2004, the borrowing under the Canadian credit facility translated to $232 million, using the applicable foreign exchange rate.

Commercial Paper; Accounts Receivable Securitization; Universal Shelf

In addition to our revolving credit agreement, we have historically relied on the commercial paper market and our accounts receivable securitization program to cover near-term borrowing requirements. At September 30, 2004, we had no outstanding balance under the commercial paper or accounts receivable securitization programs. We also have in place a universal shelf registration statement as of September 30, 2004, with an unutilized balance of approximately $1.539 billion, which is available for the future issuance of other debt and/or equity securities depending on our needs, market conditions and compliance with our negative covenants under our credit agreement. From time to time, we may also look to fund some of our long-term projects using other financing sources, including multilateral and bilateral agencies.

Credit Ratings

Maintaining investment-grade credit ratings, that is "BBB- / Baa3" and above from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively, is a significant factor in our ability to raise short-term and long-term financing. As a result of our current investment grade ratings, we have access to both the commercial paper and bank loan markets. We currently have a BBB+ / Baa2 credit rating by Standard & Poor's and Moody's, respectively, and an A-2 / Prime-2 for our commercial paper ratings. Moody's and Standard & Poor's outlooks, as of the date of the filing of this report, remained stable for our long term debt and commercial paper ratings. In the event that our credit ratings were downgraded to below investment grade, our ability to access additional short and long-term financing sources and the terms of any such financing would be adversely impacted. However, based on current commodity prices, we believe that cash generated from operating activities, asset sales and cash on hand would be sufficient for the remainder of 2004 to cover our operating and capital spending requirements for current development projects and to make expected dividend payments and to pay down scheduled debt. We also believe that our available borrowing capacity under our revolving credit agreement would be sufficient to enable us to meet unanticipated cash requirements if needed.

Off-Balance Sheet Arrangements

We have a construction completion guarantee related to debt financing associated with our equity interest in the development of the BTC pipeline project. The maximum potential future payments under the guarantee are estimated to be $310 million. Extending guarantees to creditors allows the project to reduce its borrowing costs. We are not the primary beneficiary in this arrangement. See note 17 to the consolidated financial statements for a detailed discussion.

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 September 30, 2004, our reserves for environmental remediation obligations totaled $252 million, of which $106 million was included in current liabilities. During the nine month period of 2004, cash payments of $63 million were applied against the reserves and $63 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 $225 million.

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

	At September 30, 2004	
Millions of dollars	Reserve	Estimated Possible Additional Costs
Superfund and similar sites	$ 15	$ 15
Active Company facilities	31	35
Company facilities sold with retained liabilities and former Company-operated sites	97	80
Inactive or closed Company facilities	109	95
Total	$ 252	$ 225

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

During the nine month period of 2004, provisions of $42 million were recorded for the "Company facilities sold with retained liabilities and former Company-operated sites" category. These provisions were for approximately 225 sites where we had operated service stations, bulk plants or terminals. The provisions were based on new and revised cost estimates that were developed for these sites in the nine month period of 2004. The provisions were also for new and revised cost estimates for the assessment and remediation of oil fields in Michigan and California. We will perform assessments on certain areas within these fields to determine if they have been contaminated by our former operations. We have determined that other areas within these sites are contaminated and will require remediation.

We recorded provisions of $9 million during the nine month period of 2004 for the "Active Company facilities" category of sites. The provisions were primarily for the estimated additional costs of the remedial investigation and feasibility study (RI/FS) that is continuing at a molybdenum mine located in Questa, New Mexico, which is owned by our Molycorp subsidiary. The estimated additional costs are based on an evaluation that Molycorp performed in the second quarter of 2004 of the remaining work that will be required to complete the RI/FS. Molycorp has been conducting the RI/FS cooperatively with the U.S. Environmental Protection Agency to determine what, if any, adverse impacts past mining operations may have had on the environment.

The reserve related to sites in the "Inactive or closed Company facilities" category was increased by $11 million during the nine month period of 2004. The increase was primarily for our former refinery in Beaumont, Texas and a former terminal in Edmonds, Washington. A provision was recorded for the updated cost estimates to close impoundments used in the former operations at the Beaumont, Texas site. In the first quarter of 2004, final design work and related

detailed cost estimates to close these impoundments were completed. We also received final approval of a permit for these projects from the Texas Commission on Environmental Quality. The reserve for this category of sites was also increased for the estimated cost of cleanup work at a shutdown terminal in Edmonds, Washington. The cost includes the implementation and operation of a system to remediate petroleum hydrocarbon contamination caused by our former petroleum products storage and transportation operation at the facility.

In the nine month period of 2004, estimated possible additional costs in excess of amounts included in the reserves for remediation obligations increased by $20 million. Included is an increase of $10 million for sites in the "Inactive or closed Company facilities" category. The increase is primarily for possible additional remediation costs for a molybdenum processing facility in Washington, Pennsylvania, which is owned by our Molycorp subsidiary. The remediation that may be required is for tar-contaminated soil caused by the operations of the former owner of the property.

Possible additional costs for the "Active Company facilities" category of sites increased by $5 million in the first nine months of 2004. These costs are primarily to close two impoundments and remove a pipeline at our Molycorp subsidiary's lanthanide mine in California. Releases from the impoundments and pipeline of wastewater and tailings generated by the mining and milling operation had caused soil and groundwater contamination at the facility.

During the first nine months of 2004, possible additional costs for the "Company facilities sold with retained liabilities and former Company-operated sites" category increased by $5 million. The higher costs were primarily for a former oil field in Michigan and for former service station sites at various locations. Estimated possible additional costs for the former Michigan oil field were increased for the cost of remediation that may need to be performed on certain areas within the site that may have been contaminated by the former oil field operation. These costs are based on an evaluation being performed at the site in 2004. Higher possible additional costs for the former service station sites are based on new and revised estimates of the upper end of remediation costs ranges that were developed during the nine month period of 2004.

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. Please see the cautionary statement under "Forward-Looking Statements" on page iii of this report. This outlook discusses our current expectations regarding certain important operational activities for the remainder of 2004 and for other future time periods. It is not intended to be a complete discussion of all future operational activities.

We expect energy prices to remain volatile 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. We have secured fixed price "hedges" to seek to mitigate some of that volatility, primarily relating to a portion of our 2004 and 2005 North America natural gas and crude oil production.

We believe the economic situation in Asia, where most of our international activity is centered, is becoming more positive. We look at the natural gas market in Asia as one of our major strategic investments.

Full-year 2004 production is expected to exceed 405,000 BOE per day. Our current capital expenditures forecast for the full-year 2004 is between $1.7 and $1.8 billion, down from the $2.0 billion previously forecast. The primary reason for the decrease is related to our decision to terminate our participation in five contracts to explore for, develop and market natural gas resources in the Xihu Trough off the coast of Shanghai, in the East China Sea and delays in certain development projects in deepwater Indonesia.

Exploration and Production - North America

United States

- Two new deepwater Gulf of Mexico developments are moving toward completion in 2004. The Mad Dog field (operated by BP p.l.c.) is expected to come on stream in the first quarter of 2005. The K-2 field (operated by Eni SpA.) is expected to come on stream in the second quarter of 2005. The estimate of initial net production is about 2,000 to 3,000 BOE/d from each field, rising to 5,000 to 6,000 BOE/d by the end of 2005. We have a 15.6 percent working interest in Mad Dog and a 12.5 percent working interest in K-2.

- Evaluation of the extensive well data collected from the St. Malo discovery well and the Dana Point deepening appraisal well on Walker Ridge Block 678 continues. The evaluation will focus on productivity, additional appraisal operations and the viability of development options. We have a 28.75 percent working interest in the St. Malo discovery.

- We are currently drilling a deeper zone test on the Sequoia prospect below our Mirage discovery. Following Sequoia, we expect to drill the Southwest Ridge appraisal well on the Mad Dog structure. Other deep water Gulf of Mexico drilling activities expected include follow-up wells on our Puma discovery and a deep test under the Mad Dog structure operated by BP. In addition, we expect to participate in a Miocene test on the Chilkoot prospect in Green Canyon Block 320, operated by Kerr McGee Corporation.

- In Alaska, first production from our Happy Valley discovery is expected to begin in November 2004. Exploratory drilling and evaluation is currently in progress at some prospects in the southern Kenai Peninsula with other natural gas prospects in the same area targeted for exploration.

Exploration and Production - International

Asia

Thailand:

- Thailand's electricity market continues to grow at approximately 8 percent per annum. Additional supplies of natural gas to meet that growth have been constrained by pipeline capacity. Recent de-bottlenecking activities on

the two existing pipelines in the Gulf of Thailand should allow us an opportunity for increased production in 2004 and 2005, prior to the expected completion of the third pipeline in 2006.

- Phase 2 development of the Thailand oil project is now underway. Start up is expected late in the second quarter of 2005. This project is expected to add 10,000 BOE/d net when full capacity is achieved in late third quarter of 2005.

- We anticipate signing final agreements in 2005 to extend our existing natural gas sales agreements and expand contract quantities by 15 percent by 2006, and another 50 percent by 2010-2012.

- The Arthit field's natural gas sales agreement has been signed and development work has begun with first production anticipated in late 2006 or early 2007.

Indonesia:

- At the end of the third quarter there were 24 wells completed in the West Seno field. Gross production averaged 26,000 BOE/d during the third quarter of 2004. We expect to complete Phase 1 drilling activities by the end of 2004 with a total of 28 wells. The 2004 gross exit rate for the field is expected to average between 35,000 and 45,000 BOE/d. Bids were opened for fabrication and installation of a tension leg platform and infield pipelines for Phase 2 of the West Seno field development. The bid results were unacceptably high. Currently, evaluation of extended reach drilling from the existing Phase 1 platform is being considered as a means to more cost effectively recover the resource in the southern portion of the field; however, potential production from any Phase 2 development will be after 2005.

- We are continuing to work on solidifying our development plans for our deepwater natural gas projects. Development will likely be around two major hubs. First production is expected in late 2007 from the Gendalo field where we have begun front-end engineering and design work. The second development project is expected to be the Gehem-Ranggas oil and gas complex where 10 appraisal wells have been drilled to date and where first production is expected to come on-line by 2010-2011.

- We expect exploration and appraisal drilling to continue in 2004 in the deep water Kutei Basin. This drilling activity will test new prospects in recently awarded PSCs in the deep water.

Vietnam:

- In early 2004, we signed a Heads of Agreement with PetroVietnam for natural gas development. We fulfilled our drilling commitments in the second quarter of 2004, but agreed to drill two additional wells on one block to retain additional acreage. Work continues to bring Vietnam gas to market between 2008 and 2010.

Bangladesh:

- Facility construction and development drilling on the Moulavi Bazar field is progressing. First production from Moulavi Bazar is expected late in the first quarter or early in the second quarter of 2005. The new field is expected to increase production in Bangladesh by 15,000 BOE/d when production begins and increase to 25,000 BOE/d by the end of 2005.

- We received approval for a plan of development for the Bibiyana field in second quarter of 2004 and negotiations with Petrobangla continue on a gas purchase and sales agreement. We anticipate that the gas purchase and sales agreement will be finalized in the fourth quarter of 2004. The Bibiyana field is capable of being developed in stages, which could provide Bangladesh with natural gas resources in the short, medium and long-term time frames. We expect first production by the end of 2006.

Other International

Australia:

- In the fourth quarter of 2004, we plan to participate in drilling a deepwater well on Block VIC/P52, which is located in the Otway Basin, offshore Victoria. We hold a 33.33-percent non-operating working interest in the block.

Azerbaijan:

- Progress continues in 2004 on the development of the BP operated AIOC project. Gross production is expected to ramp up to more than 200 MBbl/d in 2005, rising to 700 MBbl/d in 2007 and over 1 million Bbl/d by 2009. We have a 10.28 percent working interest. In 2005, we expect Phase 1 development to commence in the second quarter of 2005. The initial average net production rate is expected to be approximately 6,000 BOE/d for the first three months, climbing to 12,000 BOE/d in the next three months and to 18,000 BOE/d in the subsequent three months.

Midstream and Marketing

In parallel with the AIOC field development work in Azerbaijan, the BTC pipeline is expected to be fully operational in the second half of 2005. The portions of the pipeline through Azerbaijan and Georgia are expected to be complete and ready for line-fill in the second quarter of 2005. The BTC pipeline will transport the crude oil from the AIOC field 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.

Corporate and Other

On July 29, 2004, we made a voluntary pre-tax contribution of $100 million to our U.S. Qualified Retirement Plan. In addition, we expect that mandated employer contributions to the plan will not be payable until 2009. However, less than expected future returns on plan assets or a decrease in the discount rate could accelerate the requirement to make cash contributions to the plan before 2009.

On October 15, 2004, we amended the Unocal Medical Plan to set a maximum amount to our contributions for retiree medical coverage. As a result of this revision, we were required to remeasure our postretirement benefit obligation as of October 15, 2004. This calculation resulted in a net reduction of $73 million to our accumulated postretirement benefit obligation and is estimated to decrease our future annual pre-tax postretirement expense by $12 million.

In October 2004, our Molycorp subsidiary sold down its interest of its equity investment in Companhia Brasileira de Metalurgia e Mineracao, a niobium operation in Brazil, from 44.59 percent to 40 percent for $27 million.

FUTURE ACCOUNTING CHANGES

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

Additionally, 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, changes in the carryback and carryforward utilization periods for foreign tax credits and a dividend received deduction with respect to accumulated income earned abroad. The new law could potentially have an impact on our effective tax rate, future taxable income and cash and tax planning strategies, amongst other affects. We are currently in the process of evaluating the impact that the Act will have on our financial position and results of operations.

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.

Market risk generally represents the risk that losses may occur in the values of financial instruments as a result of changes in commodity prices, interest rates and 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, 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 approximately $35 million at September 30, 2004. The value at risk related to hydrocarbon derivatives held for non-hedging purposes was approximately $3 million at September 30, 2004.
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 September 30, 2004. Assuming a ten percent decrease in our weighted average borrowing costs at September 30, 2004, 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 approximately $75 million at September 30, 2004.

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 and have outstanding Canadian-dollar denominated debt.

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 September 30, 2004, we had various foreign currency forward contracts outstanding related to operations in Thailand and the Netherlands. 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 September 30, 2004, 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 approximately $13 million at September 30, 2004.

Hydrocarbon Derivatives Tables - The following tables set forth the future volumes and price ranges of hydrocarbon derivatives we held at September 30, 2004, along with the fair values of those instruments.

Open Hydrocarbon Hedging Derivative Instruments (a)

	2004	2005	2006	2007
Natural Gas Futures Positions				
Volume (MMBtu)	190,000	120,000	-	
Average price, per MMBtu	$ 5.67	$ 6.10		
Volume (MMBtu)	(1,660,000)	(14,640,000)	-	
Average price, per MMBtu	$ 6.50	$ 6.98		
Natural Gas Swap Positions				
Pay fixed price				
Volume (MMBtu)	4,203,000	14,068,000	8,568,000	14
Average swap price, per MMBtu	$ 3.93	$ 3.99	$ 3.05	
Receive fixed price				
Volume (MMBtu)	14,190,000	13,215,000	-	
Average swap price, per MMBtu	$ 5.84	$ 6.29		
Natural Gas Basis Swap Positions				
Volume (MMBtu)	455,000	-	-	
Average price received, per MMBtu	$ 6.58			
Average price paid, per MMBtu	$ 6.41			
Crude Oil Futures Positions				
Volume (Bbls)	(2,000,000)	(400,000)	-	
Average price, per Bbl	$ 42.63	$ 41.42		
Crude Oil Collar Positions				
Volume (Bbls)	180,000	-	-	
Average ceiling price, per Bbl	$ 28.40			
Average floor price, per Bbl	$ 24.00			

(a) Futures positions reflect long (short) volumes.
(b) Net claims against counterparties with non-investment grade credit ratings are immaterial.
(c) Includes $481 thousand in assumed liabilities which were capitalized as acquisition costs.

Open Hydrocarbon Non-Hedging Derivative Instruments (a)

	2004	2005

Natural Gas Futures Positions		
Volume (MMBtu)	5,500,000	1,540,000
Average price, per MMBtu	$ 5.99	$ 7.00
Volume (MMBtu)	(720,000)	(1,540,000)
Average price, per MMBtu	$ 5.37	$ 7.15
Natural Gas Swap Positions		
Pay fixed price		
Volume (MMBtu)	1,815,000	1,400,000
Average swap price, per MMBtu	$ 6.30	$ 5.92
Receive fixed price		
Volume (MMBtu)	1,590,000	1,400,000
Average swap price, per MMBtu	$ 6.05	$ 5.90
Natural Gas Basis Spread Swap Positions		
Volume (MMBtu)	9,455,000	39,930,000
Average price paid, per MMBtu	$ 0.83	$ 0.57
Volume (MMBtu)	9,760,000	39,930,000
Average price received, per MMBtu	$ 0.83	$ 0.57
Natural Gas Option (Listed & OTC)		
Call Volume -Buy-(MMBtu)	1,250,000	-
Average Call price	$ 7.00	
Call Volume -Sell-(MMBtu)	14,150,000	500,000
Average Call price	$ 6.84	$ 9.00
Put Volume -Buy-(MMBtu)	-	-
Average Put Price	$ -	
Put Volume -Sell-(MMBtu)	1,200,000	2,000,000
Average Put Price	$ 5.15	$ 4.50
Natural Gas Spread Option (Over the Counter)		
NYMEX / IFERC (c)		
Call Volume (MMBtu)	-	-
Average Strike price		
Put Volume (MMBtu)	-	1,000,000
Average Strike price		$ 0.50
Crude Oil Futures Positions		
Volume (Bbls)	5,344,000	1,275,000
Average price, per Bbl	$ 43.38	$ 40.62
Volume (Bbls)	(5,104,000)	(1,375,000)
Average price, per Bbl	$ 43.65	$ 38.89
Crude Oil Option (Listed & OTC)		
Call Volumes -Buy-(Bbls)	-	-
Average price, per Bbl	$ -	
Call Volumes -Sell-(Bbls)	500,000	400,000
Average price, per Bbl	$ 50.20	$ 55.00
Put Volume -Buy-(Bbls)	300,000	-
Average price, per Bbl	$ 44.67	
Put Volume -Sell-(Bbls)	580,000	-
Average price, per Bbl	$ 37.58	
Crude Oil Swap Positions		
Pay fixed price		
Volume (Bbls)	4,223,350	3,020,470
Average swap price, per Bbl	$ 44.78	$ 43.28
Receive fixed price		
Volume (Bbls)	4,318,820	2,847,720
Average swap price, per Bbl	$ 43.33	$ 43.21

(a) Futures positions reflect long (short) volumes.
(b) Includes $1,075 thousand net claims against counterparties with non-investment grade credit
(c) Prices quoted from the New York Mercantile Exchange (NYMEX) and Inside FERC Gas Report (IFER

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 quarter 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.

Internal Controls

Section 404 of the Sarbanes-Oxley Act of 2002 and related SEC rules thereunder will require us to include an internal control report with our 2004 Annual Report on Form 10-K. The internal control report must assert, among other things, (i) management's responsibilities to establish and maintain adequate internal control over financial reporting and (ii) management's assessment of the effectiveness of this internal control as of the end of the most recent fiscal year. Our independent registered public accounting firm will be required to audit, and report on, these assertions. Our management has formed a steering committee and adopted a detailed project work plan to assess the adequacy of our internal controls, remediate any control weaknesses that may be identified and validate through testing that controls are functioning as documented. There was no change in our internal control over financial reporting that occurred during the three months ended September 30, 2004 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 Annual Report on Form 10-K for the year ended December 31, 2003, as amended, and in Item 1 of Part II of our Quarterly Report on Form 10-Q for the quarterly periods ended

March 31 and June 30, 2004. 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 I of Part I of this report.

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

In the California Superior Court cases (the Doe and Roe cases) alleging Unocal's liability in connection with the construction of the natural gas pipeline from the Yadana field across Myanmar to the Thailand border, described in Paragraph 3 of Item 3 of the 2003 Form 10-K, the court denied a motion to dismiss and ruled that those claims related to liability (Phase II) may proceed to trial. This recent ruling does not alter the court's Phase I ruling that Unocal's foreign subsidiaries are not "alter egos" of Unocal and Union Oil.

The state court ruling does not affect a separate case against Unocal pending in the federal courts. The federal case is currently under review by an en banc panel of the Ninth Circuit Court of Appeals in San Francisco, California.

We believe that the outcomes of the federal and state cases are not likely to have a material adverse effect on our financial condition or liquidity or, based on current assessment of the cases, our results of operations. Trial has been set for June 21, 2005.

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

In the third quarter of 2004, 358,100 shares of our common stock, together with cash in lieu of fractional shares, were issued upon conversion of 304,823 of the 6-1/4% trust convertible preferred securities of Unocal Capital Trust. The shares of common stock were not registered under the Securities Act of 1933, as amended (the "1933 Act"), in reliance upon the exemption from registration afforded by Section 3(a)(9) of the 1933 Act, together with interpretations thereof by the staff of the Division of Corporation Finance of the SEC, for a security exchanged by the issuer with its existing security holders, of those of a subsidiary where no commission or other remuneration is paid or given directly or indirectly for soliciting such exchange.

The following table shows information regarding repurchases we made of our shares of common stock during the third quarter of 2004:

Period	Total Number of Shares Purchased (1)	Average Price Paid per share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	M
July 1 through July 31, 2004	41,528	$37.46	None	

August 1 through August 31, 2004	4,157,008	$36.28	4,130,000
September 1 through September 30, 2004	25,382	$39.69	None
Total	4,223,918	$36.31	4,130,000

1. During the third quarter, we cancelled 15,878 shares repurchased for the payment of withholding taxes due on restricted stock that vested under various employee restricted stock plans.

   During the third quarter, we purchased 78,108 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. In December 1996, our board of directors authorized the repurchase of $400 million of our common stock. In January 1998, our board extended the stock repurchase program, increasing the authorized amount by $200 million. There is no expiration date to the repurchase program. At the beginning of the third quarter of 2004, we had a balance of $189 million remaining for additional repurchases. In August 2004, we purchased approximately $150 million of our common stock under this program, resulting in a balance of approximately $39 million for additional purchases.

3. In October 2004, our board of directors authorized the repurchase from time to time of shares of our common stock in order to offset the number of shares of common stock issued or delivered 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.

ITEM 6. EXHIBITS.

The Exhibit Index on page 58 of this report lists the exhibits that are filed or furnished, as applicable, as part of 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: November 4, 2004

By: /s/JOE D. CECIL

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

EXHIBIT INDEX

3. Bylaws of Unocal, as amended through September 1, 2004 and currently in effect (incorporated by reference to Exhibit 3.ii to Unocal's Current Report on Form 8-K dated and filed September 1, 2004, File No. 1-8483).

10. Five-Year Credit Agreement, dated as of August 12, 2004, among Union Oil Company of California and the borrowing subsidiaries from time to time party thereto, as Borrowers; Unocal Corporation, as Guarantor; JPMorgan Chase Bank, as Administrative Agent and Issuing Bank, Citicorp USA, Inc., as Syndication Agent, and the lenders from time to time party thereto (incorporated by reference to Exhibit 10 to Unocal's Current Report on Form 8-K dated August 12, 2004, and filed August 18, 2004, File No. 1-8483).

12.1 Statement regarding computation of ratio of earnings to fixed charges of Unocal Corporation for the nine months ended September 30, 2004 and 2003.

12.2 Statement regarding computation of ratio of earnings to fixed charges of Union Oil Company of California for the nine months ended September 30, 2004 and 2003.

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.