

L 3 COMMUNICATIONS HOLDINGS INC

Form 4

October 22, 2014

FORM 4**UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549**

OMB APPROVAL

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STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934,
 Section 17(a) of the Public Utility Holding Company Act of 1935 or Section
 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
 Dunwoody Ann E.

2. Issuer Name and Ticker or Trading Symbol
 L 3 COMMUNICATIONS HOLDINGS INC [LLL]

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

(Last) (First) (Middle)

3. Date of Earliest Transaction
 (Month/Day/Year)
 10/21/2014

☒ Director ☐ 10% Owner
☐ Officer (give title below) ☐ Other (specify below)

C/O L-3 COMMUNICATIONS CORPORATION, 600 THIRD AVENUE

(Street)

4. If Amendment, Date Original Filed(Month/Day/Year)

6. Individual or Joint/Group Filing(Check Applicable Line)
☒ Form filed by One Reporting Person
☐ Form filed by More than One Reporting Person

NEW YORK, NY 10016

(City) (State) (Zip)

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1. Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)	4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)	5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Ownership (Instr. 4)
Common Stock	10/21/2014 ⁽¹⁾		A	249	A	110.15 \$ ⁽²⁾	3,044 ⁽³⁾ D

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474
 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(e.g., puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)	5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)	6. Date Exercisable and Expiration Date (Month/Day/Year)	7. Title and Amount of Underlying Securities (Instr. 3 and 4)	8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Own Follo Repo Trans (Instr
				Code	V (A) (D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares

Reporting Owners

Reporting Owner Name / Address

Relationships

Director 10% Owner Officer Other

Dunwoody Ann E.
C/O L-3 COMMUNICATIONS CORPORATION
600 THIRD AVENUE
NEW YORK, NY 10016

X

Signatures

/s/ Allen E. Danzig as
Attorney-in-Fact

10/22/2014

__Signature of Reporting Person

Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

Date on which the Reporting Person became entitled to receive RSUs (in lieu of cash) for service as a director ("Compensation Date").

(1) These RSUs were fully vested as of the Compensation Date. Vested RSUs do not convert into shares of Common Stock until the date on which a Reporting Person ceases to be a director of the Issuer. Dividends are reinvested, resulting in an increase in the number of RSUs subject to the award.

(2) Closing price per share of the Issuer's Common Stock on the Compensation Date.

(3) Does not include shares issuable upon the exercise of options.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.

Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. ames 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 -15- work to be performed, who will perform the work, the timing of the work, who will pay for the work and other factors that may have an impact on the timing of the payments for amounts included in the reserve.

For some sites, the remediation work will be performed by other parties, such as the current owners of the sites, and we have a contractual agreement to pay a share of the remediation costs. For these sites, we generally have less control over the timing of the work and consequently the timing of the associated payments. Based on available information, we estimate that the majority of the amounts included in the reserve will be paid within the next three to five years. At the sites where we have contractual agreements to share remediation costs with third parties, the reserve reflects our estimated shares of those costs. In many of the oil and gas sites, remediation cost sharing is included in joint venture agreements that were made with third parties during the original operation of the sites. In many cases where we sold facilities or a business to a third party, sharing of remediation costs for those sites may be included in the sales agreement.

Superfund and similar sites Contamination at the sites of the "Superfund and similar sites" category was the result of the disposal of substances at these sites by one or more PRPs. Contamination of these sites could be from many sources, of which we may be one. We have been notified that we are a PRP at the sites included in this category. At the sites where we have not denied liability, our contribution to the contamination at these sites was primarily from operations in the other categories described below. Included in this category of sites are: o the McColl site in Fullerton, California o the Operating Industries site in Monterey Park, California o the Casmalia Waste site in Casmalia, California. At June 30, 2005, we have received notifications from the EPA that we may be a PRP at 21 sites and may share certain liabilities at these sites. Of the total, three sites are under investigation and/or litigation, and our potential liability is not presently determinable. Of the remaining 18 sites, where we have concluded that liability is probable and to the extent costs can be reasonably estimated, a reserve of \$8 million has been established for future remediation and settlement costs. Various state agencies and private parties have identified 23 other similar PRP sites. Four sites are under investigation and/or litigation, and our potential liability is not presently determinable; and at three sites, our potential liability appears to be de minimis. Where we have concluded that liability is probable and to the extent costs can be reasonably estimated at the remaining 16 sites, a reserve of \$4 million has been established for future remediation and settlement costs. The sites discussed above exclude 132 sites where our liability has been settled, or where we have no evidence of liability and there has been no further indication of liability by government agencies or third parties for at least a 12-month period. We do not consider the number of sites for which we have been named a PRP as a relevant measure of liability. Although the liability of a PRP is generally joint and several, we are usually just one of numerous companies designated as a PRP. Our ultimate share of the remediation costs at those sites often is not determinable due to many unknown factors. The solvency of other responsible parties and disputes regarding responsibilities may also impact our ultimate costs.

Active Company facilities The "Active Company facilities" category includes oil and gas fields and mining operations. The oil and gas sites are primarily contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Contamination at the active mining sites was principally the result of the impact of mined material on the groundwater and/or surface water at these sites. Included in this category are: o the Molybdenum mine in Questa, New Mexico o the Molybdenum facility in Mountain Pass, California o Alaska oil and gas properties. -16- We have a reserve of \$25 million for estimated future costs of remedial orders, corrective actions and other investigation, remediation and monitoring obligations at certain operating facilities and producing oil and gas fields. We recorded provisions of \$2 million during the first six months of 2005. During the first six months of 2005, we made payments of \$7 million for this category of sites.

Company facilities sold with retained liabilities and former Company operated sites The "Company facilities sold with retained liabilities and former Company-operated sites" category includes our former refineries, transportation and distribution facilities and service stations. The required remediation of these sites is mainly for petroleum hydrocarbon contamination as the result of leaking tanks, pipelines or other equipment or impoundments that were used in these operations. Also included in this category are former oil and gas fields that we no longer operate. In most cases, these sites are contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Contamination at other sites in these categories of sites was the result of former industrial chemical and polymers manufacturing and distribution facilities and agricultural chemical retail businesses. Included in this category are: 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 issues that resulted from operations prior to the sale. The reserve represents estimated future costs for remediation work: identified prior to the sale of these sites; included in negotiated agreements with the buyers of these sites where we retained certain levels of remediation liabilities; and/or identified in subsequent claims made by buyers of the

properties. Our former operated sites include service stations, distribution facilities and oil and gas fields that we previously operated but did not own. We have an aggregate reserve of \$100 million for this group of sites. During the first six months of 2005, provisions of \$25 million for this category were recorded. These provisions were primarily for sites that we formerly operated and were based on new and revised cost estimates that we identified during 2005 for the remediation of approximately 125 service station, bulk plant and terminal sites and for the assessment and remediation of oil and gas fields in Central California. Payments of \$26 million were made during the first six months of 2005 for sites in this category. Inactive or closed Company facilities The "Inactive or closed Company facilities" category includes former oil and gas fields and other locations that are no longer operating. In most cases, these sites are contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Other sites in this category were contaminated from former ferromolybdenum production operations. Included in this category are: 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 \$102 million has been established for these types of facilities. During the first six months of 2005, we accrued \$15 million related to sites in this category, primarily for the Guadalupe oil field site. Soil at this site has been contaminated with diluent, a kerosene-like additive used in the field's former operations. The provision includes revised estimated costs for remediation work that is required by the cleanup and abatement order for the site. The required remediation work has become better defined through ongoing and continuing meetings and negotiations with the regulatory agencies. This work includes studies, operation and maintenance of remedial systems, restoration, and regulatory agency oversight and permitting procedures. Payments of \$12 million were made during the first six months of 2005 for sites in this category.

-17- Legal Compliance We are subject to federal, state and local environmental laws and regulations, including CERCLA, as amended, RCRA and laws governing low-level radioactive materials. Under these laws, we are subject to existing and/or possible obligations to remove or mitigate the environmental effects of the disposal or release of certain chemical, petroleum and radioactive substances at various sites. Corrective investigations and actions pursuant to RCRA and other federal, state and local environmental laws are being performed at our facility in Beaumont, Texas, a former agricultural chemical facility in Corcoran, California, MolyCorp's facility in Washington, Pennsylvania and other facilities. In addition, MolyCorp is required to decommission its Washington facility in Pennsylvania pursuant to the terms of its radioactive source materials license and decommissioning plan. We also must provide financial assurance for future closure and post-closure costs of our RCRA-permitted facilities and for decommissioning costs at MolyCorp's Washington Pennsylvania facility under its radioactive source materials license. Pursuant to a 1998 settlement agreement between us and the State of California (and the subsequent stipulated judgment entered by the Superior Court), we must provide financial assurance for anticipated costs of remediation activities at our former Guadalupe oil field. As previously discussed, remediation reserves for these sites are included in the "Inactive or closed Company facilities" category and totaled \$88 million at June 30, 2005. At those sites where investigations or feasibility studies have advanced to the stage of analyzing alternative remedies and/or ranges of costs, we estimate that we could incur possible additional remediation costs aggregating approximately \$75 million. Although any possible additional costs for these sites are likely to be incurred at different times and over a period of many years, we believe that these obligations could have a material adverse effect on our results of operations but are not expected to be material to our consolidated financial condition or liquidity.

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

Certain Litigation and Claims Petrobangla Claim: Our subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. received a letter from Petrobangla claiming, on behalf of itself and the Bangladesh government, compensation allegedly due in the amount of \$685 million for 246 BCF of recoverable natural gas allegedly "lost and damaged" in a 1997 blowout and ensuing fire during the drilling by Occidental Petroleum Corporation (known at that time in Bangladesh as Occidental of Bangladesh Ltd.) ("OBL"), as operator, of the Moulavi Bazar #1 exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. Unocal and OBL believe that the claim vastly overstates the amount of recoverable natural gas involved in the blowout. For a further discussion of this claim, refer to the "Petrobangla Claim" section under note 23 to the consolidated financial statements in Item 8 of our 2004 10-K.

Chevron Merger Litigation: Unocal and its ten

directors are defendants in two putative class action lawsuits challenging the acquisition of Unocal by Chevron. Initial complaints were brought by individual Unocal stockholders in April 2005 in the Superior Court of California in Los Angeles. The actions were consolidated and a consolidated complaint was filed on July 14, 2005 alleging that Unocal and its directors breached their fiduciary duties by (i) failing to maximize stockholder value; (ii) securing benefits for certain officers and directors of Unocal at the expense of its stockholders; and (iii) improperly favoring Chevron over other potential bidders by tailoring the merger agreement to Chevron and erecting obstacles to deter other interested bidders. In general terms, the plaintiffs challenge the acquisition price, officer compensation, and the size of the termination fee contained in the Chevron merger agreement. The consolidated complaint brings a single claim of breach of fiduciary duties. The lawsuit, *Lieb v. Unocal et al.*, seeks equitable relief by way of an injunction against the Chevron merger, an order directing Unocal to obtain a transaction more favorable to Unocal's stockholders, an order to set aside the merger if consummated and the imposition -18- of a constructive trust, as well as unspecified amount of damages to Unocal's stockholders sustained as a result of the Chevron merger and attorney's fees. On July 27, 2005, a separate lawsuit was filed in federal court in Los Angeles, purportedly brought on behalf of a class of Unocal stockholders. The action, entitled *Alaska Electrical Pension Fund v. Unocal Corp., et al.*, Case No. CV05-5420 JFW, asserts claims and allegations, and seeks relief, substantially similar to the consolidated actions filed in California state court, which are described above. We believe we have substantial meritorious defenses to the claims. Unocal and Chevron have reached an agreement in principle with the state court plaintiffs providing for the settlement of the putative stockholder class action brought in California state court in connection with the proposed Chevron merger. In connection with the settlement, it was agreed that Unocal would make certain disclosures, which are set forth in the Additional Disclosure Relating to the Proposed Merger with Chevron Corporation filed with the SEC on July 29, 2005. Further, under the terms of settlement, and subject to certain conditions, all claims relating to the merger agreement and the proposed merger will be dismissed and released on behalf of the settlement class and the state court plaintiffs will withdraw their challenges to the proposed merger. The settlement is subject to California state court approval. Prior to the time at which the settlement will be submitted to the California state court for final approval, additional information will be provided to class members in a notice of settlement. Tax Matters We believe we have adequately provided in our accounts for tax items and issues not yet resolved. Several prior material tax issues are unresolved. Resolution of these tax issues affects not only the year in which the items arose, but also our tax situation in other tax years. With respect to the 1979-1994 taxable years, the Joint Committee on Taxation of the U.S. Congress reviewed and approved the settlement of all issues for these years, including the carryback of a 1993 net operating loss to taxable year 1984 and resultant credit adjustments, as previously agreed with the Appeals division of the Internal Revenue Service ("IRS"). This settlement and corresponding recalculation of taxable income and credits for this period resulted in an overpayment of taxes. We received cash refunds of \$72 million in 2004 and \$6 million in 2005, representing overpaid taxes plus interest thereon. Taxable years 1979-1990 are now closed and barred from additional assessment of federal income taxes. Although the IRS has completed its audit of Unocal for taxable years 1991-1994 and a settlement has been reached for all such years, these years cannot be formally closed until a separate audit by the IRS of the Alaska Kuparuk River Unit tax partnership is closed. The Kuparuk tax partnership audit has been completed and is in the process of being closed. No material adjustments to taxable income are required. However, until this tax partnership audit is formally closed, our corporate tax audit remains technically open. Accordingly, the IRS refers to the 1991-1994 taxable years as "partially closed." All such developments have been considered in our accounts. With respect to the 1995-1997 taxable years, a settlement of all issues was reached with the Appeals division of the IRS. Although the IRS has completed its audit of Unocal for taxable years 1995-1997 and a settlement has been reached for all such years, these years cannot be formally closed until a separate audit by the IRS of the Alaska Kuparuk River Unit tax partnership is closed. The Kuparuk tax partnership audit has been completed and is in the process of being closed. No material adjustments to taxable income are required. However, until this tax partnership audit is formally closed, our corporate tax audit remains technically open. Accordingly, the IRS refers to the 1995-1997 taxable years as "partially closed." All such developments have been considered in our accounts. The 1998-2001 taxable years are before the Exam division of the IRS. Guarantees Related to Assets or Obligations of Third Parties Future Remediation Costs We have agreed to indemnify certain third parties for particular future remediation costs that may be incurred for properties held by these parties. The guarantees were established when we either leased property from or sold property to these third parties. The properties may or may not have been contaminated by our former operations. Where it has been or will be determined that we are responsible for

contamination, the guarantees require us to pay the costs to remediate the sites to specified cleanup levels or to levels that will be determined in the future. -19- The maximum potential amount of future payments that we could be required to make under these guarantees is indeterminate primarily due to the following: the indefinite term of the majority of these guarantees; the unknown extent of possible contamination; uncertainties related to the timing of the remediation work; possible changes in laws governing the remediation process; the unknown number of claims that may be made; changes in remediation technology; and the fact that most of these guarantees lack limitations on the maximum potential amount of future payments. We have accrued probable and reasonably estimable assessment and remediation costs for the locations covered under these guarantees. These amounts are included in the "Company facilities sold with retained liabilities and former Company-operated sites" category of our reserve for environmental remediation obligations. At June 30, 2005, the reserve for this category totaled \$100 million. For those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, we estimate that we could incur possible additional remediation costs aggregating approximately \$80 million.

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

Other Guarantees and Indemnities We have also guaranteed the debt of certain other entities accounted for by the equity method. The majority of this debt matures ratably through the year 2014. The maximum potential amount of future payments we could be required to make is \$14 million. In the ordinary course of business, we have agreed to indemnify cash deficiencies for certain domestic pipeline joint ventures, which we account for on the equity method. These guarantees are considered in our analysis of overall risk. Because most of these agreements do not contain spending caps, it is not possible to quantify the amount of maximum payments that may be required. Nevertheless, we believe the payments would not have a material adverse impact on our financial condition or liquidity.

Financial Assurance for Unocal Obligations Surety Bonds and Letters of Credit In the normal course of business, we have performance obligations that are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily cover self-insurance, site restoration, dismantlement and other programs where governmental organizations require such support. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed by us if drawn upon. At June 30, 2005, we had obtained various surety bonds for \$166 million. These surety bonds included a bond for \$58 million securing our performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of natural gas over a ten-year period that began in January of 1999 and will end in December of 2008 and \$108 million in various other routine performance bonds held by local, city, state and federal agencies. We also had obtained \$121 million in standby letters of credit at June 30, 2005, of which \$29 million represented letters of credit with the revenue department in Thailand relating to tax appeals, \$41 million represented letters of credit for collateral and margin requirements for crude oil and natural gas purchases and \$12 million represented additional collateral related to the aforementioned bond for the fixed price natural gas sales contract. We have entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit.

-20- **Other Guarantees and Credit Rating Triggers** We have various other guarantees for approximately \$500 million. Approximately \$118 million of the \$500 million in guarantees represent financial assurance we gave on behalf of our MolyCorp subsidiary relating to permits covering operations and discharges from MolyCorp's Questa, New Mexico, molybdenum mine. Our financial assurance is for the completion of temporary closure plans (required only upon cessation of operations) and other obligations required under the terms of the permits. The costs associated with the financial assurance are based on estimations provided by agencies of the state of New Mexico. Guarantees for approximately \$280 million of the \$500 million would require us to obtain a surety bond or a letter of credit or establish a trust fund if our credit rating were to drop below investment grade -- that is BBB- or Baa3 from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively.

Classification on Balance Sheet Approximately \$240 million of the surety bonds, letters of credit and other guarantees that we are required to obtain or issue reflect obligations that are already included on the consolidated balance sheet in other current liabilities and other deferred credits. The surety bonds, letters of credit and other guarantees may also reflect some of the possible additional remediation liabilities discussed earlier in this note.

Other Matters Our lease

agreement for the Discoverer Spirit deepwater drillship has a current minimum daily rate of approximately \$229,000. The future remaining minimum lease payment obligation was \$18 million at June 30, 2005. The contract will expire on September 18, 2005. We also have other contingent liabilities for litigation, claims and contractual agreements arising in the ordinary course of business. Based on management's assessment of the ultimate amount and timing of possible adverse outcomes and associated costs, none of these other matters is presently expected to have a material adverse effect on our consolidated financial condition, liquidity or results of operations.

18. Financial Instruments and Commodity Hedging Interest rate contracts - We enter into interest rate swap contracts to manage our debt with the objective of minimizing the volatility and magnitude of our borrowing costs. We may also enter into interest rate option contracts to protect our interest rate positions, depending on market conditions. At June 30, 2005, we had approximately \$19 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges of interest rate exposures through September 2012. Of this amount, approximately \$3 million in after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months. Foreign currency contracts - Various foreign exchange currency forward, option and swap contracts are entered into from time to time to manage our exposures to adverse impacts of foreign currency fluctuations on recognized obligations and anticipated transactions. At June 30, 2005, we had no deferred amounts in accumulated other comprehensive income on the consolidated balance sheet related to foreign currency contracts. Commodity hedging activities - We use hydrocarbon derivatives to mitigate our overall exposure to fluctuations in hydrocarbon commodity prices. Ineffectiveness for cash flow and fair value hedges was immaterial for the six months of 2005. At June 30, 2005, we had \$9 million of after-tax deferred losses in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future commodity sales for the period beginning July 2005 through December 2005. All of the after-tax losses are expected to be reclassified to the consolidated earnings statement during the next twelve months. Fair values for debt and other long-term instruments - The estimated fair values of our long-term debt and capital leases were \$2.80 billion at June 30, 2005. Fair values were based on the discounted amounts of future cash outflows using the rates offered to us for debt with similar remaining maturities.

-21- 19. Supplemental Condensed Consolidating Financial Information Unocal guarantees all the publicly held securities issued by its 100 percent-owned subsidiary Union Oil. Such guarantees are full and unconditional and no subsidiaries of Unocal or Union Oil guarantee these securities. The following tables present condensed consolidating financial information for (a) Unocal (Parent), (b) Union Oil (Parent) and (c) on a combined basis, the subsidiaries of Union Oil (non-guarantor subsidiaries). Virtually all of our operations are conducted by Union Oil and its subsidiaries.

CONDENSED CONSOLIDATED EARNINGS STATEMENT For the Three Months Ended June 30, 2005 Non- Unocal Union Oil Guarantor Millions of dollars (Parent) (Parent) Subsidiaries Eliminations Consolidated

----- Revenues Sales and	
operating revenues \$ - \$ 416 \$ 2,031 \$ (286) \$ 2,161	Interest, dividends and miscellaneous income - 7 40 (5) 42
Gain on sales of assets - 2 8 - 10	
----- Total revenues - 425	
2,079 (291) 2,213	Costs and other deductions Purchases, operating and other expenses 3 323 1,162 (286) 1,202
Depreciation, depletion and amortization - 79 190 - 269	Impairments - - 1 - 1
Dry hole costs - 10 2 - 12	Interest expense - 28 9 (5) 32
----- Total costs and	
other deductions 3 440 1,364 (291) 1,516	Equity in earnings of subsidiaries 477 524 - (1,001) -
Earnings from equity investments - (22) 40 - 18	
----- Earnings from	
continuing operations before income taxes and minority interests 474 487 755 (1,001) 715	
----- Income taxes (1) 4	
270 - 273	Minority interests - - 2 - 2
----- Earnings from	
continuing operations 475 483 483 (1,001) 440	Earnings from discontinued operations - (6) 41 - 35
----- Net earnings \$ 475 \$	
477 \$ 524 \$ (1,001) \$ 475	

-22- CONDENSED CONSOLIDATED EARNINGS STATEMENT For the Three Months Ended June 30, 2004 Non-Unocal Union Oil Guarantor Millions of dollars (Parent) (Parent) Subsidiaries Eliminations Consolidated

operating revenues \$ - \$ 318 \$ 1,711 \$ (230) \$ 1,799	Revenues Sales and
Interest, dividends and miscellaneous income 1 1 19 (2) 19	
Gain on sales of assets - (40) 80 - 40	

	Total revenues 1
279 1,810 (232) 1,858	
Costs and other deductions Purchases, operating and other expenses 3 292 1,124 (231) 1,188	
Depreciation, depletion and amortization - 65 148 - 213	
Impairments - 3 6 - 9 Dry hole costs - 10 26 - 36	
Interest expense 9 31 8 (2) 46	

	Total costs and
other deductions 12 401 1,312 (233) 1,492	
Equity in earnings of subsidiaries 350 443 - (793) -	Earnings from equity
investments - 2 37 (1) 38	

	Earnings from
continuing operations before income taxes and minority interests 339 323 535 (793) 404	

	Income taxes (2)
(29) 169 - 138	
Minority interests - - (1) - (1)	

	Earnings from
continuing operations 341 352 367 (793) 267	
Earnings from discontinued operations - (2) 76 - 74	

	Net earnings \$ 341 \$
350 \$ 443 \$ (793) \$ 341	

-23- CONDENSED CONSOLIDATED EARNINGS STATEMENT For the Six Months Ended June 30, 2005 Non-Unocal Union Oil Guarantor Millions of dollars (Parent) (Parent) Subsidiaries Eliminations Consolidated

operating revenues \$ - \$ 818 \$ 3,921 \$ (539) \$ 4,200	Revenues Sales and
Interest, dividends and miscellaneous income - 14 45 (8) 51	
Gain on sales of assets - 2 28 - 30	

	Total revenues - 834
3,994 (547) 4,281	
Costs and other deductions Purchases, operating and other expenses 6 624 2,257 (539) 2,348	
Depreciation, depletion and amortization - 147 365 - 512	
Impairments - - 1 - 1 Dry hole costs - 11 20 - 31	
Interest expense 1 55 17 (8) 65	

	Total costs and
other deductions 7 837 2,660 (547) 2,957	
Equity in earnings of subsidiaries 934 968 - (1,902) -	Earnings from equity
investments - (21) 78 - 57	

	Earnings from
continuing operations before income taxes and minority interests 927 944 1,412 (1,902) 1,381	

	Income taxes (2) 4
503 - 505	
Minority interests - - 4 - 4	

	Earnings from
continuing operations 929 940 905 (1,902) 872	
Earnings from discontinued operations - (6) 63 - 57	

	Net earnings \$ 929 \$
934 \$ 968 \$ (1,902) \$ 929	

-24- CONDENSED CONSOLIDATED EARNINGS STATEMENT For the Six Months Ended June 30, 2004 Non-Unocal Union Oil Guarantor Millions of dollars (Parent) (Parent) Subsidiaries Eliminations Consolidated

operating revenues \$ - \$ 644 \$ 3,311 \$ (436) \$ 3,519	Revenues Sales and
Interest, dividends and miscellaneous income 1 5 27 (3) 30	
Gain on sales of assets - (16) 100 - 84	

	Total revenues 1
633 3,438 (439) 3,633	
Costs and other deductions Purchases, operating and other expenses 5 521 2,208 (437) 2,297	
Depreciation, depletion and amortization - 128 288 - 416	
Impairments - 6 8 - 14 Dry hole costs - 27 32 - 59	
Interest expense 17 57 16 (3) 87	

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----- Total costs and
other deductions 22 739 2,552 (440) 2,873 Equity in earnings of subsidiaries 628 681 - (1,309) - Earnings from equity
investments - 3 73 (1) 75
----- Earnings from
continuing operations before income taxes and minority interests 607 578 959 (1,309) 835
----- Income taxes (3)
(52) 364 - 309 Minority interests - - 4 - 4
----- Earnings from
continuing operations 610 630 591 (1,309) 522 Earnings from discontinued operations - (2) 90 - 88
----- Net earnings \$ 610 \$
628 \$ 681 \$ (1,309) \$ 610

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-25- CONDENSED CONSOLIDATED BALANCE SHEET At June 30, 2005 Non- Unocal Union Oil Guarantor
Millions of dollars (Parent) (Parent) Subsidiaries Eliminations Consolidated

----- Assets Current
assets Cash and cash equivalents \$ 1 \$ 1,174 \$ 600 \$ - \$ 1,775 Accounts and notes receivable - net 137 190 1,077
(137) 1,267 Inventories - 7 235 (77) 165 Assets held for sale - - 1,372 - 1,372 Other current assets - 88 31 - 119
----- Total current assets
138 1,459 3,315 (214) 4,698 Properties - net - 1,910 5,899 (3) 7,806 Other assets including goodwill 6,969 6,077 945
(12,726) 1,265 -----
Total assets \$7,107 \$ 9,446 \$ 10,159 \$ (12,943) \$ 13,769

----- Liabilities and Stockholders' Equity Current liabilities Accounts payable \$ - \$ 332 \$ 954 \$ (137) \$ 1,149 Current
portion of long-term debt - 185 279 - 464 Liabilities of assets held for sale - - 411 - 411 Other current liabilities 54
266 412 - 732 ----- Total
current liabilities 54 783 2,056 (137) 2,756 Long-term debt and capital leases - 1,464 612 - 2,076 Deferred income
taxes - (224) 815 - 591 Accrued abandonment, restoration and environmental liabilities - 371 495 - 866 Other deferred
credits and liabilities - 708 389 (4) 1,093 Minority interests - - 17 12 29 Stockholders' equity 7,053 6,344 5,775
(12,814) 6,358 -----
Total liabilities and stockholders' equity \$7,107 \$ 9,446 \$ 10,159 \$ (12,943) \$ 13,769

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-26- CONDENSED CONSOLIDATED BALANCE SHEET At December 31, 2004 Non- Unocal Union Oil
Guarantor Millions of dollars (Parent) (Parent) Subsidiaries Eliminations Consolidated

----- Assets Current
assets Cash and cash equivalents \$ - \$ 691 \$ 469 \$ - \$ 1,160 Accounts and notes receivable - net 55 239 1,184 (55)
1,423 Inventories - 8 289 (77) 220 Other current assets - 101 26 - 127
----- Total current assets
55 1,039 1,968 (132) 2,930 Properties - net - 1,935 6,887 (3) 8,819 Other assets including goodwill 6,095 5,713 430
(10,886) 1,352 -----
Total assets \$6,150 \$ 8,687 \$ 9,285 \$ (11,021) \$ 13,101

----- Liabilities and Stockholders' Equity Current liabilities Accounts payable \$ - \$ 278 \$ 1,074 \$ (54) \$ 1,298 Current
portion of long-term debt 242 162 87 - 491 Other current liabilities 54 244 496 (2) 792
----- Total current
liabilities 296 684 1,657 (56) 2,581 Long-term debt and capital leases - 1,648 923 - 2,571 Deferred income taxes -
(156) 995 - 839 Accrued abandonment, restoration and environmental liabilities - 373 524 - 897 Other deferred credits
and liabilities - 663 309 (3) 969 Minority interests - - 15 12 27 Stockholders' equity 5,854 5,475 4,862 (10,974) 5,217
----- Total liabilities and
stockholders' equity \$6,150 \$ 8,687 \$ 9,285 \$ (11,021) \$ 13,101

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-27- CONDENSED CONSOLIDATED CASH FLOWS For the Six Months Ended June 30, 2005 Non- Unocal Union

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Oil Guarantor Millions of dollars (Parent) (Parent) Subsidiaries Eliminations Consolidated

	Cash Flows from
Operating Activities Net cash provided by operating activities	\$ 2 \$ 780 \$ 850 \$ - \$ 1,632
Cash Flows from Investing Activities Capital expenditures and acquisitions (includes dry hole costs)	- (149) (724) - (873)
Proceeds from sales of assets and discontinued operations	- 14 150 - 164
	Net cash used in
investing activities	- (135) (574) - (709)
	Cash Flows from
Financing Activities Change in long-term debt	(14) (162) (114) - (290)
Dividends paid on common stock	(107) - - (107)
Proceeds from issuance of common stock	120 - - 120
Other	- (3) - (3)
	Net cash used in
financing activities	(1) (162) (117) - (280)
	Total increase in
cash and cash equivalents	1 483 159 - 643
	Less: Cash and cash
equivalents of assets held for sale	- - 28 - 28
	Cash and cash
equivalents at beginning of period	- 691 469 - 1,160
	Cash and cash
equivalents at end of period	\$ 1 \$ 1,174 \$ 600 \$ - \$ 1,775

CONDENSED CONSOLIDATED CASH FLOWS For the Six Months Ended June 30, 2004 Non- Unocal Union Oil Guarantor Millions of dollars (Parent) (Parent) Subsidiaries Eliminations Consolidated

	Cash Flows from
Operating Activities Net cash provided by operating activities	\$ 7 \$ 613 \$ 506 \$ - \$ 1,126
Cash Flows from Investing Activities Capital expenditures and acquisitions (includes dry hole costs)	- (131) (670) - (801)
Proceeds from sales of assets and discontinued operations	- 28 250 - 278
Return of capital from affiliate company	- - 48 - 48
	Net cash used in
investing activities	- (103) (372) - (475)
	Cash Flows from
Financing Activities Change in long-term debt	- (193) 87 - (106)
Dividends paid on common stock	(105) - - (105)
Proceeds from issuance of common stock	94 - - 94
Repurchases of common stock	(20) - - (20)
Other	24 (2) (1) - 21
	Net cash provided
by (used in) financing activities	(7) (195) 86 - (116)
	Increase in cash and
cash equivalents	- 315 220 - 535
	Cash and cash
equivalents at beginning of period	1 45 358 - 404
	Cash and cash
equivalents at end of period	\$ 1 \$ 360 \$ 578 \$ - \$ 939

-28- 20. Segment Data Our reportable segments are: (1) Exploration and Production, (2) Midstream and Marketing, and (3) Geothermal. General corporate overhead, unallocated costs and other miscellaneous operations, including real estate, carbon and minerals and those businesses that were sold or being phased-out, are included under the Corporate and Other heading. On July 8, 2005, we entered into a Share Purchase Agreement with Pogo to sell all of the outstanding capital stock in our Northrock subsidiary in Canada. This transaction includes our exploration and production assets in Western Canada (see note 21 for further detail).

	Segment Information
Exploration and Production For the Three Months North America International Ended June 30, 2005	Total Millions of
dollars U.S. Canada Total N.A. Asia Other Total Intl E&P	
	Sales & operating revenues \$

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303 \$ 1 \$ 304 \$ 546 \$ 111 \$ 657 \$ 961 Other income (loss) (a) - - - (1) 11 10 10 Inter-segment sales & operating revenues 286 - 286 184 - 184 470

----- Total 589 1 590 729 122 851

1,441 Earnings from equity investments - - - 15 - 15 15 Earnings (loss) from continuing operations 146 - 146 294 53

347 493 Earnings from discontinued operations (net) - 25 25 - - - 25

----- Net earnings (loss) 146 25

171 294 53 347 518 ----- Assets

(at June 30, 2005) 3,323 1,372 4,695 3,758 1,195 4,953 9,648

----- Midstream Geothermal

Corporate and Other Total and Net Environ- Marketing Admin & Interest mental & (b) General Expense Litigation Other(c) ----- Sales & operating revenues \$ 1,108 \$ 45 \$ - \$ - \$ - \$ 47 \$ 2,161 Other income (loss) (a) 28 (1) - 11 - 4 52 Inter-segment sales & operating revenues 46 - - - - (516) -

----- Total 1,182 44 - 11 - (465)

2,213 Earnings from equity investments (9) - - - - 12 18 Earnings (loss) from continuing operations 20 17 (28) (21)

(27) (14) 440 Earnings from discontinued operations (net) - - - - - 10 35

----- Net earnings (loss) 20 17 (28)

(21) (27) (4) 475 ----- Assets (at

June 30, 2005) 1,225 487 - - - 2,409 13,769

----- (a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets. (b) Sales & operating revenues include \$197 million of crude oil buy/sell transactions settled in cash. (c) Includes eliminations and consolidation adjustments. -29-

----- Segment Information

Exploration and Production For the Three Months North America International Ended June 30, 2004 Total Millions of dollars U.S. Canada Total N.A. Asia Other Total Intl E&P

----- Sales & operating revenues \$

197 \$ 1 \$ 198 \$ 356 \$ 79 \$ 435 \$ 633 Other income (loss) (a) 35 - 35 1 1 2 37 Inter-segment sales & operating revenues 229 - 229 100 - 100 329

----- Total 461 1 462 457 80 537

999 Earnings from equity investments - - - 12 2 14 14 Earnings (loss) from continuing operations 108 - 108 137 29

166 274 Earnings from discontinued operations (net) 46 16 62 - - - 62

----- Net earnings (loss) 154 16

170 137 29 166 336 ----- Assets

(at December 31, 2004) 3,307 1,376 4,683 3,661 1,007 4,668 9,351

----- Midstream Geothermal

Corporate and Other Total and Net Environ- Marketing Admin & Interest mental & (b) General Expense Litigation Other(c) ----- Sales & operating revenues \$ 969 \$ 124 \$ - \$ - \$ - \$ 73 \$ 1,799 Other income (loss) (a) 3 13 - 4 - 2 59 Inter-segment sales & operating revenues 38 - - - - (367) -

----- Total 1,010 137 - 4 - (292) 1,858 Earnings from equity investments 12 (2) - - - 14 38 Earnings (loss) from continuing operations 18 57 (21) (33) (11) (17) 267 Earnings from discontinued operations (net) 13 - - - - (1) 74

----- Net earnings (loss) 31 57 (21)

(33) (11) (18) 341 ----- Assets (at

December 31, 2004) 1,303 573 - - - 1,874 13,101

----- (a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets. (b) Sales & operating revenues include \$210 million of crude oil buy/sell transactions settled in cash. (c) Includes eliminations and consolidation adjustments. -30-

----- Segment Information

Exploration and Production For the Six Months North America International Ended June 30, 2005 Total Millions of

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dollars U.S. Canada Total N.A. Asia Other Total Intl E&P

----- Sales & operating revenues \$
607 \$ 4 \$ 611 \$ 1,005 \$ 209 \$ 1,214 \$ 1,825 Other income (loss) (a) 4 - 4 (10) 18 8 12 Inter-segment sales &
operating revenues 538 - 538 357 - 357 895

----- Total 1,149 4 1,153 1,352
227 1,579 2,732 Earnings from equity investments - - - 28 - 28 28 Earnings (loss) from continuing operations 300 1
301 545 101 646 947 Earnings from discontinued operations (net) - 42 42 - - - 42

----- Net earnings (loss) 300 43
343 545 101 646 989 ----- Assets
(at June 30, 2005) 3,323 1,372 4,695 3,758 1,195 4,953 9,648

----- Midstream Geothermal
Corporate and Other Total and Net Environ- Marketing Admin & Interest mental & (b) General Expense Litigation
Other(c) ----- Sales & operating
revenues \$ 2,206 \$ 88 \$ - \$ - \$ - \$ 81 \$ 4,200 Other income (loss) (a) 30 - - 19 - 20 81 Inter-segment sales & operating
revenues 87 - - - (982) - -----
Total 2,323 88 - 19 - (881) 4,281 Earnings from equity investments 7 - - - 22 57 Earnings (loss) from continuing
operations 55 34 (57) (36) (39) (32) 872 Earnings from discontinued operations (net) - - - - 15 57
----- Net earnings (loss) 55 34 (57)
(36) (39) (17) 929 ----- Assets (at
June 30, 2005) 1,225 487 - - - 2,409 13,769

----- (a) Includes interest,
dividends and miscellaneous income, and gain (loss) on sales of assets. (b) Sales & operating revenues include \$360
million of crude oil buy/sell transactions settled in cash. (c) Includes eliminations and consolidation adjustments. -31-

----- Segment Information
Exploration and Production For the Six Months North America International Ended June 30, 2004 Total Millions of
dollars U.S. Canada Total N.A. Asia Other Total Intl E&P

----- Sales & operating revenues \$
495 \$ 3 \$ 498 \$ 708 \$ 136 \$ 844 \$ 1,342 Other income (loss) (a) 45 - 45 2 2 4 49 Inter-segment sales & operating
revenues 435 - 435 202 - 202 637

----- Total 975 3 978 912 138
1,050 2,028 Earnings from equity investments - - - 22 2 24 24 Earnings (loss) from continuing operations 221 - 221
295 46 341 562 Earnings from discontinued operations (net) 49 28 77 - - - 77

----- Net earnings (loss) 270 28
298 295 46 341 639 ----- Assets
(at December 31, 2004) 3,307 1,376 4,683 3,661 1,007 4,668 9,351

----- Midstream Geothermal
Corporate and Other Total and Net Environ- Marketing Admin & Interest mental & (b) General Expense Litigation
Other(c) ----- Sales & operating
revenues \$ 1,918 \$ 164 \$ - \$ - \$ - \$ 95 \$ 3,519 Other income (loss) (a) 8 45 - 10 - 2 114 Inter-segment sales &
operating revenues 72 - - - (709) - -----
----- Total 1,998 209 - 10 - (612)
3,633 Earnings from equity investments 28 (1) - - - 24 75 Earnings (loss) from continuing operations 41 94 (48) (65)
(27) (35) 522 Earnings from discontinued operations (net) 13 - - - (2) 88
----- Net earnings (loss) 54 94 (48)
(65) (27) (37) 610 ----- Assets (at
December 31, 2004) 1,303 573 - - - 1,874 13,101

----- (a) Includes interest,
dividends and miscellaneous income, and gain (loss) on sales of assets. (b) Sales & operating revenues include \$462
million of crude oil buy/sell transactions settled in cash. (c) Includes eliminations and consolidation adjustments. 21.

Explanation of Responses:

Subsequent Event On July 8, 2005, Unocal and two of its Canadian subsidiaries entered into a Share Purchase Agreement with Pogo and one of its Canadian subsidiaries. The agreement provides that Unocal will sell all of the outstanding capital stock in its Northrock subsidiary in Canada to Pogo for US\$1.8 billion in cash. For a copy of the agreement and additional information regarding the pending sale, refer to our current report on Form 8-K, filed with the SEC on July 12, 2005. On July 29, 2005, we repaid our \$200 million Canadian dollar-denominated term loan which was scheduled to mature in November 2009. The amount repaid translated to \$163 million, using the applicable foreign exchange rate. -32- ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS. You should read the following discussion and analysis of our financial condition and results of operations in conjunction with Management's Discussion and Analysis in Item 7 of our 2004 10-K and the consolidated financial statements and related notes therein. Our 2004 10-K contains a discussion of other matters not included herein, such as disclosures regarding critical accounting policies and estimates, contractual obligations and our credit facilities and other financing sources. You should read the following discussion and analysis together with the cautionary statement under "Forward-Looking Statements" on page iii of this report, which is incorporated into this item 2. RECENT DEVELOPMENTS Pending Merger with Chevron On April 4, 2005, we entered into a merger agreement with Chevron Corporation and Blue Merger Sub Inc., a direct wholly-owned subsidiary of Chevron. The merger agreement provides that, upon the terms and subject to the conditions set forth in the merger agreement, Unocal would merge with and into Blue Merger Sub and the separate corporate existence of Unocal would cease, with Blue Merger Sub remaining as the surviving corporation in the merger. On June 22, 2005, Unocal received an unsolicited competing proposal from CNOOC Limited ("CNOOC"), an affiliate of China National Offshore Oil Company, to acquire all outstanding shares of Unocal for \$67 per share in cash. On June 23, 2005, Chevron granted Unocal a waiver under the Chevron merger agreement enabling Unocal, at any time prior to the date of the Unocal stockholder vote on the merger with Chevron, to negotiate with CNOOC and its representatives without the need for Unocal's board to make certain threshold determinations that otherwise would be required under the Chevron merger agreement. On July 1, 2005, we filed with the SEC a final joint proxy statement/prospectus for the special meeting of Unocal stockholders, scheduled for August 10, 2005, to vote on the Chevron merger. On July 19, 2005, following discussions and negotiations with CNOOC with respect to the CNOOC proposal as well as negotiations with Chevron with respect to the Chevron transaction, Unocal, Chevron and Blue Merger Sub entered into an amendment to the Chevron merger agreement. This amendment has the effect of increasing the merger consideration paid to Unocal stockholders for their shares. Pursuant to the amended merger agreement, each Unocal stockholder would have the right to elect to receive, for each Unocal share: o a combination of 0.618 of a share of Chevron common stock and \$27.60 in cash; o 1.03 shares of Chevron common stock; or o \$69 in cash. The all-stock and all-cash elections above would be subject to proration to preserve an overall per share mix of 0.618 of a share of Chevron common stock and \$27.60 in cash for all of the outstanding shares of Unocal common stock taken together. On July 25, 2005, we filed with the SEC a supplement to our proxy statement for the special stockholders meeting to vote on the Chevron merger. On August 1, 2005, Institutional Shareholder Services recommended that Unocal stockholders vote for the merger with Chevron. On August 2, 2005, CNOOC withdrew its bid proposal. Unocal and Chevron currently expect to complete the merger promptly after Unocal stockholders approve and adopt the amended merger agreement and the merger at the special meeting, currently scheduled to be held on August 10, 2005, and after the satisfaction or waiver of all other conditions to the merger. We currently expect this to occur shortly after the special meeting. However, there can be no assurance that the conditions to closing will be met or that the merger will be completed shortly after the special meeting. -33- The foregoing description of the merger and the merger agreement, as amended, does not purport to be complete and is qualified in its entirety by reference to the merger agreement, as amended, which has been filed as Exhibit 2.1 to our Form 8-K filed on April 7, 2005 (original merger agreement) and Exhibit 2.1 to our Form 8-K filed on July 22, 2005 (amendment no. 1 to the merger agreement). For additional information regarding the pending merger, refer to Unocal's current reports on Form 8-K, as amended, filed with the SEC on April 4, April 7, June 9, June 10, June 23, June 24, June 30, July 6, July 20, July 22, July 29 and August 1, 2005, and any subsequent current or periodic reports that may be filed by Unocal with the SEC in connection with the pending merger transaction. Please also refer to the Form S-4 registration statement filed by Chevron and the proxy statement, as supplemented, that was filed by Unocal, in each case with the SEC in connection with the pending merger transaction. Pending Sale of Canadian Exploration and Production Business On July 8, 2005, we entered into an agreement with Pogo to sell all of the outstanding capital stock in our

wholly owned Northrock subsidiary in Canada for \$1.8 billion in cash. We expect to realize after-tax proceeds from the sale of approximately \$1.5 billion. Northrock represents essentially all of our Canadian oil and gas reserves and production. Northrock had reserves of 110 million BOE at year-end 2004, less than 7 percent of our worldwide hydrocarbon reserves, and average daily net production of 28,100 BOE in the second quarter of 2005. The Northrock transaction, which is subject to customary Canadian regulatory approvals, is expected to close in the third quarter of 2005. OVERVIEW Our primary line of business is the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids. Our principal operations are in North America and Asia. We are also a leading producer of geothermal energy in Asia. Other activities include ownership in proprietary and common carrier pipelines, natural gas storage facilities and the marketing of hydrocarbon commodities. Fluctuations in hydrocarbon commodity prices and the resulting impact on our realized prices for liquids and North America natural gas are a significant driver of our financial performance. In addition to developments regarding our pending merger with Chevron, which have been discussed elsewhere in this report and in our other public disclosures, some of our more significant operational highlights and other activities from the first six months of 2005 are listed below: o began crude oil and natural gas production from the Mad Dog and K-2 fields in the Gulf of Mexico, o began production from Phase 2 of the Thailand crude oil project, o began production from Phase 1 of the ACG crude oil project in the Azerbaijan sector of the Caspian Sea and continued progress on Phase 2 and 3 of the project, o began line-fill of the BTC crude oil export pipeline from the Caspian Sea to Turkey, o began natural gas and condensate production from the Moulavi Bazar field in Bangladesh, o encountered hydrocarbons in a secondary objective at the Knotty Head well, located in Green Canyon Block 512 in the Gulf of Mexico, o encountered hydrocarbons in an appraisal well drilled on the deepwater Mad Dog Southwest Ridge in the Gulf of Mexico, which was further delineated by three sidetracks, o entered into a farm-in agreement for acreage in the Turkey and Georgia sections of the Eastern Black Sea, and o completed the redemption of our outstanding 6-1/4% convertible junior subordinated debentures. Commodity Prices and Operating Results Commodity prices remained volatile during the first six months of 2005. Commodity prices reached all-time highs in June and July of 2005. Our worldwide production increased by 9 percent in the first six months of 2005 compared to the first six months of 2004 primarily due to increased production from Thailand, Indonesia, Bangladesh and Azerbaijan. Rising production costs remain a challenge as the entire oil services industry attempts to benefit from the higher commodity price environment through pricing increases. -34- The following table summarizes our net daily production and average prices for our North America and International Exploration and Production business units: For the Three Months For the Six Months Ended June 30, Ended June 30,

	2005	2004	2005	2004
----- North America Net Daily Production Liquids				
(thousand barrels) U.S.	61	55	59	55
Canada	14	15	15	16
----- Total liquids 75 70 74 71				
Natural gas - dry basis				
(million cubic feet) U.S.	442	511	448	512
Canada	83	83	83	83
----- Total natural gas 525 594 531 595				
North America				
Average Prices (excluding hedging activities) (a) Liquids (per barrel) U. S. \$48.72 \$35.91 \$46.60 \$33.66				
Canada	\$37.67	\$29.89	\$38.00	\$29.17
Average	\$46.56	\$34.58	\$44.85	\$32.66
Natural gas (per mcf) U. S. \$ 5.91 \$ 4.80 \$ 5.68 \$				
5.20	Canada	\$ 6.35	\$ 5.40	\$ 6.02
\$ 5.37	Average	\$ 5.98	\$ 4.88	\$ 5.74
\$ 5.23				
----- North America Average Prices (including hedging				
activities) (a) Liquids (per barrel) U. S. \$48.04 \$30.52 \$46.39 \$29.64				
Canada	\$37.67	\$29.89	\$38.00	\$29.17
Average	\$46.02	\$30.38	\$44.68	\$29.54
Natural gas (per mcf) U. S. \$ 5.89 \$ 4.53 \$ 6.02 \$ 5.34				
Canada	\$ 6.35	\$ 5.08	\$ 6.02	\$
5.06	Average	\$ 5.97	\$ 4.61	\$ 6.02
\$ 5.30				
----- (a)				
Excludes gains/losses on derivative positions not accounted for as hedges and ineffective portions of hedges. -35- For				
the Three Months For the Six Months Ended June 30, Ended June 30, ----- 2005 2004				
2005 2004				
----- International Net Daily Production (a)				
Liquids (thousand barrels) Asia	74	61	75	64
Other (b)	28	20	24	20
----- Total liquids 102 81 99 84				
Natural gas - dry basis				
(million cubic feet) Asia	1,156	891	1,083	885
Other (b)	10	31	10	28
----- Total natural gas 1,166 922 1,093 913				
International				
Average Prices (c) Liquids (per barrel) Asia \$49.77 \$34.02 \$47.63 \$32.66				
Other	\$48.31	\$36.01	\$47.74	\$34.30
Average	\$49.43	\$34.52	\$47.66	\$33.02
Natural gas (per mcf) Asia \$ 3.38 \$ 3.02 \$ 3.39 \$ 2.99				
Other	\$ 5.45	\$ 4.01	\$	\$

5.35 \$ 4.17 Average \$ 3.40 \$ 3.03 \$ 3.41 \$ 3.01 -----
 Worldwide Net Daily Production (b) Liquids (thousand barrels) 177 151 173 155 Natural gas - dry basis (million cubic feet) 1,691 1,516 1,624 1,508 Barrels oil equivalent (thousands) 459 404 444 406 Worldwide Average Prices (excluding hedging activities)(d) Liquids (per barrel) \$48.18 \$34.55 \$46.43 \$32.86 Natural gas (per mcf) \$ 4.20 \$ 3.76 \$ 4.17 \$ 3.89 Worldwide Average Prices (including hedging activities) (d) Liquids (per barrel) \$47.94 \$32.61 \$46.35 \$31.41 Natural gas (per mcf) \$ 4.20 \$ 3.65 \$ 4.26 \$ 3.92

----- (a) International production is presented utilizing the economic interest method. (b) Includes proportional interests in production of equity investees of: Liquids - 1 - 1 Natural gas - 20 - 17 Barrels oil equivalent - 5 - 4 (c) International did not have any hedging activities. (d) Excludes gains/losses on derivative positions not accounted for as hedges and ineffective portions of hedges. -36-

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

----- Millions of dollars 2005 2004 2005 2004
 ----- Earnings from continuing operations \$ 440 \$ 267 \$
 872 \$ 522 Earnings from discontinued operations 35 74 57 88
 ----- Net earnings \$ 475 \$ 341 \$ 929 \$ 610

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Earnings From Continuing Operations Second Quarter Results: 2nd quarter earnings in 2005 increased \$173 million, or 65 percent, vs. 2nd quarter 2004 primarily due to the following factors: Positive Variance Factors o Higher worldwide commodity prices in the current quarter increased net earnings by approximately \$180 million. o International production was higher in the current quarter and contributed about \$70 million in higher earnings, primarily from new production in Bangladesh, increased volumes from the ACG crude oil project in Azerbaijan and increased volumes from our Indonesia and Thailand operations. o Lower net interest expense due primarily to lower debt levels increased net earnings by \$12 million. o Lower exploration costs due primarily to lower exploration drilling activity in Indonesia and Thailand contributed approximately \$20 million in higher earnings. o In the prior year quarter, we recorded a provision of \$46 million pre-tax (\$29 million after-tax) associated with the arbitration ruling regarding Agrium's Kenai, Alaska nitrogen-based fertilizer plant. Negative Variance Factors o Lower United States natural gas production reduced net earnings by about \$20 million in the current quarter due primarily to natural production declines. o After-tax environmental and litigation expenses were \$28 million in the second quarter of 2005, compared with \$15 million in the same period a year ago. o In 2004, our Geothermal segment settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines and recorded an after-tax settlement gain of \$46 million. o In the current quarter of 2005, various tax related adjustments resulted in a charge to tax expense of approximately \$10 million. In the prior year quarter, we recorded a net tax benefit of \$27 million for settlements and assessments with various taxing authorities. o In the prior year quarter, our subsidiary, Pure Resources Inc. ("Pure"), recorded a \$22 million after-tax gain from the sale of exploratory mineral fee lands. -37-

Six Months Results: earnings in the first six months of 2005 increased \$350 million, or 67 percent, vs. the first six months of 2004 primarily due to the following factors: Positive Variance Factors o Higher worldwide commodity prices in 2005 increased net earnings by approximately \$335 million. o International production was higher in 2005 and contributed about \$100 million in higher earnings, primarily from new production in Bangladesh and increased volumes from the ACG crude oil project and our Indonesia and Thailand operations. o Lower net interest expense due primarily to lower debt levels increased net earnings by \$29 million. o Higher results from our pipeline business along with higher margins from our North America natural gas storage business increased net earnings by \$13 million. o Higher results from our minerals business increased net earnings by \$17 million. o In 2004, we recorded a provision of \$46 million pre-tax (\$29 million after-tax) associated with the arbitration ruling regarding Agrium's Kenai, Alaska

nitrogen-based fertilizer plant. Negative Variance Factors o Lower United States natural gas production reduced net earnings by about \$45 million in 2005 due primarily to natural production declines. o In 2004, we settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines and recorded an after-tax settlement gain of \$46 million. o In 2005, various tax related adjustments resulted in a charge to tax expense of approximately \$10 million, and in 2004 we recorded a net tax benefit of \$27 million for settlements and assessments with various taxing authorities. o Higher employee related expenses reduced net earnings by about \$15 million. o After-tax environmental and litigation expenses were \$41 million in 2005, compared with \$38 million in 2004. o The first six months of 2005 included approximately \$32 million in after-tax gains from asset sales, primarily from the sale of miscellaneous oil and gas properties compared with the first six months of 2004, which included approximately \$54 million in after-tax gains from asset sales, primarily from the sale of certain of Pure's exploratory mineral fee lands in the U.S. and the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia. o The first six months of 2004 included a \$15 million gain from a litigation settlement related to a previous asset sale. Sales and Operating Revenues From Continuing Operations Second Quarter Results: 2nd quarter sales and operating revenues in 2005 increased by \$362 million, or 20 percent, vs. 2nd quarter 2004 primarily due to the following factors: Positive Variance Factors o Higher average commodity prices from our exploration and production activities, excluding Canada, increased sales revenues by about \$300 million. Our worldwide average realized liquids price was \$48.90 per Bbl, which was an increase of \$15.98 per Bbl, or 49 percent, from 2004. Our average realized liquids price included losses from our hedging activities of 26 cents and \$2.15 per Bbl in 2005 and 2004, respectively. Our worldwide average realized natural gas price was \$4.09 per Mcf in 2005, which was an increase of 52 cents per Mcf, or 15 percent, from the \$3.57 per Mcf, realized in 2004. Our average worldwide natural gas price was not impacted by hedging activities in the second quarter of 2005 while the second quarter of 2004 included losses of 10 cents per Mcf. o Sales and operating revenues from marketing activities were \$935 million in the second quarter of 2005, compared with \$851 million in the same period a year ago. The increase was primarily due to higher liquids and natural gas prices partially offset by lower marketing volume activity for both liquids and natural gas. During the second quarters of 2005 and 2004, approximately 21 percent and 28 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from outside parties by our Midstream and Marketing segment. These percentages in both periods included crude oil buy/sell transactions. Crude oil buy/sell amounts were primarily lower due to a significant decrease in volumes associated with these -38- transactions, which was partially offset by higher crude oil prices (see crude oil buy/sell discussions in Item 8 of our 2004 10-K in the consolidated financial statements under notes 1 and 2). These marketing activities allowed us to better manage commodity-related risk by effectively transferring commodities from production locations to industry marketing centers with higher volumes of commercial activity and greater market liquidity. o Higher International production increased sales revenues by approximately \$125 million primarily due to increased production from the ACG crude oil project in Azerbaijan and higher Thailand natural gas production compared to the second quarter of 2004. o Higher liquids production in the United States increased sales revenues by approximately \$10 million primarily due to production from deepwater fields in the Gulf of Mexico. Negative Variance Factors o In the United States, lower natural gas production reduced sales revenues by approximately \$40 million. Most of the decline in the second quarter of 2005 was due to natural field declines. o In 2004, our Geothermal segment settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines and recorded \$77 million to sales and operating revenues as part of the pre-tax settlement gain. Six Months Results: sales and operating revenues in 2005 increased by \$681 million, or 19 percent, vs. 2004 primarily due to the following factors: Positive Variance Factors o Higher average commodity prices from our exploration and production activities, excluding Canada, increased sales revenues by approximately \$555 million. Our worldwide average realized liquids price was \$47.17 per Bbl, which was an increase of \$15.51 per Bbl, or 49 percent, from 2004. Our average realized liquids price included losses from our hedging activities of 8 cents and \$1.62 per Bbl in 2005 and 2004, respectively. Our worldwide average realized natural gas price was \$4.17 per Mcf in 2005, which was an increase of 31 cents per Mcf, or 8 percent, from the \$3.86 per Mcf, realized in 2004. Our average worldwide natural gas price included gains from our hedging activities of 10 cents and 5 cents per Mcf in 2005 and 2004, respectively. o Sales and operating revenues from marketing activities were \$1.83 billion in 2005, compared with \$1.68 billion in 2004. During the first six months of 2005 and 2004, approximately 22 percent and 29 percent, respectively, of sales and operating revenues were attributable to the resale of crude oil, natural gas and natural gas liquids purchased from

outside parties by our Midstream and Marketing segment. These percentages in both periods included crude oil buy/sell transactions. Crude oil buy/sell amounts were primarily lower due to a significant decrease in volumes associated with these transactions, which was partially offset by higher crude oil prices. o Higher International production increased sales revenues by approximately \$200 million primarily due to increased production from the ACG crude oil project in Azerbaijan and higher Thailand natural gas production compared to 2004. o Higher liquids production in the United States increased sales revenues by approximately \$15 million primarily due to production from deepwater fields in the Gulf of Mexico. -39- Negative Variance Factors o In the United States, lower natural gas production reduced sales revenues by approximately \$75 million. Most of the decline in 2005 was due to natural field declines. o In 2004, our Geothermal segment settled an outstanding eight-year dispute over operation of the Tiwi and Mak-Ban geothermal steam fields in the Philippines and recorded \$77 million to sales and operating revenues as part of the pre-tax settlement gain. Income Taxes Income taxes on earnings from continuing operations for the second quarter and six month periods of 2005 were \$273 million and \$505 million, respectively, compared with \$138 million and \$309 million for the comparable periods of 2004. The effective income tax rates for the second quarter and six month periods of 2005 were 38 percent and 37 percent, respectively, compared with 34 percent and 37 percent for the same periods a year ago. The overall higher effective tax rate in the second quarter of 2005 compared to 2004 is due primarily to a net deferred tax benefit of \$27 million recorded in the second quarter of 2004 for settlements and assessments with various taxing authorities. The effective tax rate for the six month period of 2005 included net tax related benefits accrued related to the sale of Unocal Bharat and other assets along with the tax benefit effect of currency related adjustments in Thailand. The effective income tax rate for the six month period of 2004 included the effect of the aforementioned net deferred tax benefit of \$27 million as well as the tax benefit effect in 2004 of currency related adjustments in Thailand. -40- Earnings From Discontinued Operations In May 2005, we announced our intention to sell our Western Canadian exploration and production assets, and, in July 2005, we entered into an agreement to sell all of the outstanding capital stock in our wholly owned Northrock subsidiary in Canada (see note 21 for further detail). At June 30, 2005, these assets were held for sale (see note 11 for further detail), and we have classified the results from these operations as a discontinued operation. In April 2005, we sold our needle coke business for \$25 million in cash plus net working capital. We recorded an after-tax gain of approximately \$12 million in the second quarter of 2005. The gain on disposal plus the results of operations prior to the sale are reported in discontinued operations on the consolidated earnings statement. In June 2004, we sold certain of our prospective and producing mineral fee lands in the U.S., which included approximately 2 MBOE/d of production in Mississippi, Arkansas and Alabama. The producing portion of these mineral fee lands resulted in an after-tax gain of approximately \$43 million. The gain on the asset disposal plus the results of operations prior to the sale are reported in discontinued operations. In May 2004, we also sold our Cal Ven Pipeline system located in Alberta, Canada and recorded an after-tax gain of approximately \$13 million. The gain on disposal plus the results of operations prior to the sale are reported in discontinued operations. The following table summarizes the revenues, gain on disposal and total earnings from each of these discontinued operations: For the Three Months For the Six Months Ended June 30, ----- Millions of dollars 2005 2004 2005 2004

	2005	2004	2005	2004
Revenues				
Exploration and Production - U.S. \$ - \$ 6 \$ - \$ 12 - Canada	123	101	241	202
Total Exploration and Production	\$ 123	\$ 107	\$ 241	\$ 214
Midstream and Marketing - Cal Ven Pipeline - - - 1 Corporate & Other - Needle Coke Business	13	21	54	30
Total revenues from discontinued operations	\$ 136	\$ 128	\$ 295	\$ 245
Gain on disposal of discontinued operations				
Exploration and Production - U.S. \$ - \$ 43 \$ - \$ 43 Midstream and Marketing - Cal Ven Pipeline - 13 - 13 Corporate & Other - Former Refining and Marketing - - 2 - Corporate & Other - Needle Coke Business	12	-	12	-
Total gain on disposal of discontinued operations	\$ 12	\$ 56	\$ 14	\$ 56
Earnings from discontinued operations				
Exploration and Production - U.S. \$ - \$ 46 \$ - \$ 49 - Canada	25	16	42	28

----- Total Exploration
and Production \$ 25 \$ 62 \$ 42 \$ 77 Midstream and Marketing - Cal Ven Pipeline - 13 - 13 Corporate & Other -
Former Refining and Marketing - - 2 - Corporate & Other - Needle Coke Business 10 (1) 13 (2)
----- Total earnings from
discontinued operations \$ 35 \$ 74 \$ 57 \$ 88
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-41- BUSINESS SEGMENT RESULTS See note 20 to the consolidated financial statements in Item 1 of this report for additional details on our reportable segments. The following business segment results should be read in conjunction with the historical financial information provided in the consolidated financial statements and accompanying notes in Item 8 of our 2004 10-K, the consolidated results discussed earlier in this Item 2 and the business and properties descriptions in Items 1 and 2 of our 2004 10-K. Our operations are organized in the following business segments: Exploration and Production North America - Included in this category are our oil and gas operations in the United States and Canada. Our exploration and production assets in Western Canada are now included as discontinued operations (see notes 6, 11 and 21 to the consolidated financial statements in Item 1 of this report). Second Quarter Results: Earnings from continuing operations totaled \$146 million in the second quarter of 2005 compared to \$108 million for the same period a year ago, which was an increase of \$38 million. Higher natural gas and liquids prices contributed \$90 million in higher earnings in the second quarter of 2005 compared with the same quarter a year ago. The positive impact from higher prices was partially offset by lower natural gas production in the second quarter of 2005 compared with the same period a year ago, which reduced after-tax earnings by approximately \$20 million. United States natural gas production averaged 442 MMcf/d down from 511 MMcf/d in 2004. Most of the natural gas production decline was due to natural field declines primarily in the Gulf of Mexico. The prior year quarter results included a \$22 million after-tax gain from the sale of certain of Pure's exploratory mineral fee lands in the United States. Six Months Results: Earnings from continuing operations totaled \$301 million in the first six months of 2005 compared to \$221 million for the same period a year ago, which was an increase of \$80 million. Higher natural gas and liquids prices contributed \$160 million in higher earnings in the first six months of 2005 compared with the same period a year ago. Higher liquids production in the United States increased after-tax earnings by approximately \$10 million primarily due to production from deepwater fields in the Gulf of Mexico. The positive impact from higher prices and higher liquids production was partially offset by lower natural gas production in the first six months of 2005 compared with the same period a year ago, which reduced after-tax earnings by approximately \$45 million. United States natural gas production averaged 448 MMcf/d down from 512 MMcf/d in 2004. Most of the natural gas production decline was due to natural field declines primarily in the Gulf of Mexico. The first six months of 2004 included the \$22 million after-tax gain from the sale of certain of Pure's exploratory mineral fee lands in the United States and a \$15 million gain from a litigation settlement related to a previous asset sale. International - Our International operations encompass oil and gas exploration and production activities outside of North America. Through our International subsidiaries, we operate or participate in production operations in Thailand, Indonesia, Myanmar, Bangladesh, the Netherlands, Azerbaijan and the Democratic Republic of Congo. Second Quarter Results: Earnings from continuing operations totaled \$347 million in the second quarter of 2005 compared to \$166 million in the second quarter of 2004. The increase was primarily due to higher liquids and natural gas prices, which increased net earnings by approximately \$95 million. In addition, higher production principally from Indonesia, Thailand, Bangladesh and Azerbaijan contributed approximately \$70 million to after-tax earnings. International liquids production averaged 102 MBbl/d in the current quarter, up from 81 MBbl/d in the same period a year ago, while natural gas production averaged 1,166 MMcf/d in the second quarter of 2005 up from 922 MMcf/d in the same period a year ago, which was an increase of 26 percent for both liquids and natural gas. Exploration costs in the current quarter were approximately \$20 million lower than the second quarter of 2004, primarily due to lower exploration drilling activity in Indonesia and Thailand. Six Months Results: Earnings from continuing operations totaled \$646 million in the first six months of 2005 compared to \$341 million in the first six months of 2004. The increase was primarily due to higher liquids and natural gas prices, which increased net earnings by approximately \$180 million. In addition, higher production principally from Indonesia, Thailand, Bangladesh and Azerbaijan contributed approximately \$100 million to after-tax earnings. International liquids production averaged 99 MBbl/d in the first six months of 2005, up from 84 MBbl/d a year ago, while natural gas production averaged 1,093 MMcf/d up from 913 MMcf/d in the same period a year ago, which was an increase of 18 percent -42- and 20 percent,

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

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

Second Quarter Results: Earnings from continuing operations totaled \$20 million in the current quarter compared to \$18 million in the second quarter of 2004. The current period reflects improved results primarily from our pipeline businesses which included a gain on the sale of a domestic pipeline. The segment's sales and operating revenues were \$1.15 billion in the current quarter compared to \$1.01 billion in the same quarter a year ago. Included in these totals were sales from marketing activities totaling \$935 million in the current quarter compared to \$851 million in the same quarter a year ago, representing approximately 43 percent and 47 percent of our total sales and operating revenues for the second quarters of 2005 and 2004, respectively. Sales from marketing activities include buy/sell transactions. The majority of the increase in the segment's sales was primarily due to higher liquids and natural gas prices partially offset by lower marketing volume activity for both liquids and natural gas.

Six Months Results: Earnings from continuing operations totaled \$55 million in the first six months of 2005 compared to \$41 million in the same period a year ago. The results for the current year reflect improved results from our pipeline and natural gas storage businesses. The segment's sales and operating revenues were \$2.29 billion in the first six months of 2005 compared to \$1.99 billion in the same period a year ago. Included in these totals were sales from marketing activities totaling \$1.83 billion in the current six month period compared to \$1.68 billion in the same period a year ago, representing approximately 44 percent and 48 percent of our total sales and operating revenues for the 2005 and 2004 periods, respectively. Sales from marketing activities include buy/sell transactions. The increase in the segment's sales was due to higher liquids and natural gas prices partially offset by lower marketing volume activity for both liquids and natural gas. In addition, the increase in sales and operating revenues reflected higher sales volumes from our natural gas storage business.

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

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

-43- Six Months Results: Earnings from continuing operations totaled \$34 million in the first six months of 2005 compared to \$94 million in the same period a year ago. The 2004 results included the \$46 million after-tax gain from the settlement of the outstanding contract dispute in our Philippines operations and a \$21 million after-tax gain from the sale of our rights and interests in the Sarulla geothermal project on the island of Sumatra, Indonesia. Our Philippines results were higher in the current year, which was attributable to the new contract. In addition, the 2004 results included losses from an equity interest in a natural gas-fired power plant which we sold in 2005.

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

Second Quarter Results: The results from continuing operations for the current quarter were a loss of \$90 million compared to a loss of \$82 million in the same period a year ago. Net interest expense for the current quarter was \$21 million compared to \$33 million in the same quarter a year ago. After-tax expenses for environmental and litigation matters for the current

quarter were \$27 million compared to \$14 million in the same quarter a year ago. The current quarter reflected \$6 million after-tax in higher results from our minerals business due primarily to higher margins attributable to molybdenum prices. In the second quarter of 2004, we recorded a provision of \$46 million pre-tax (\$29 million after-tax) associated with the arbitration ruling regarding Agrium's Kenai, Alaska nitrogen-based fertilizer plant, and our obligations to supply natural gas to the plant. In the current quarter, various tax related adjustments resulted in a charge to tax expense of approximately \$10 million. In 2004, we recorded a net tax benefit of \$27 million for settlements and assessments with various taxing authorities. Six Months Results: The results from continuing operations for the first six months of 2005 were a loss of \$164 million compared to a loss of \$175 million in the same period a year ago. Net interest expense for the first six months of 2005 was \$36 compared to \$65 million in the same period a year ago. After-tax expenses for environmental and litigation matters for the six months of 2005 were \$40 million compared to \$35 million after-tax for the same period a year ago. The current year reflected \$17 million after-tax in higher results from our minerals business due primarily to higher margins attributable to molybdenum prices. The current year also reflected \$15 million in higher employee related expenses. In the current year, various tax related adjustments resulted in a charge to tax expense of approximately \$10 million. In the six month period of 2004, we recorded the aforementioned provision of \$29 million after-tax associated with the arbitration ruling regarding Agrium's Kenai, Alaska nitrogen-based fertilizer plant and the net tax benefit of \$27 million for settlements and assessments with various taxing authorities. LIQUIDITY AND CAPITAL RESOURCES Overview Cash and cash equivalents on hand totaled \$1.78 billion at June 30, 2005, up from \$1.16 billion at the end of 2004. As previously discussed, we have agreed in our merger agreement with Chevron, among other things, that we will not engage in certain kinds of transactions during the interim period between the execution of the agreement and the consummation of the merger, including limitations on our ability to incur debt, issue securities and sell material assets. If we were to seek to engage in a restricted activity under these covenants, we would be required to obtain the prior consent of Chevron. Based on current commodity prices and current development projects, we do not anticipate that these contractual limitations will materially adversely affect our ability to satisfy our liquidity needs during this interim period and we expect that cash generated from operating activities, routine asset sales and cash on hand will be sufficient in 2005 to cover our operating and capital spending requirements, to make expected dividend payments and to pay down scheduled debt. In addition, we believe that our available borrowing capacity is sufficient to enable us to meet unanticipated cash requirements if needed. On July 8, 2005, we agreed to sell all of the stock of our Northrock subsidiary in Canada to Pogo for \$1.8 billion in cash. We expect to realize after-tax proceeds from the sale of approximately \$1.5 billion. The sale, which is subject to customary Canadian regulatory approvals, is expected to close in the third quarter of 2005. -44- On July 29, 2005, we repaid our \$200 million Canadian dollar-denominated term loan which was scheduled to mature in November 2009. The amount repaid translated to \$163 million, using the applicable foreign exchange rate. Cash Flows from Operating Activities Cash flows from operating activities were \$1.63 billion for the six months ended June 30, 2005, compared with \$1.13 billion for the same period a year ago. The increase principally reflected the effects of higher worldwide commodity prices. Capital Expenditures and Other Investing Activities Capital expenditures were \$873 million for the first six months of 2005 compared with \$801 million in the same period a year ago. The capital expenditure amounts included \$52 million and \$63 million in 2005 and 2004, respectively, from our Canadian operation currently held for sale. The current period results reflected \$60 million and \$25 million in higher expenditures from International and United States operations, respectively. In the first six months of 2005, capital expenditures included approximately \$355 million for the development of undeveloped proved oil and gas reserves, primarily in Thailand and Azerbaijan. Asset Sales Pre-tax proceeds from asset sales relating to continuing and discontinued operations were \$164 million for the six month period ended June 30, 2005. The current year included pre-tax proceeds of \$26 million from the sale of a subsidiary that held our equity interest in an exploration and production company in India. Our Molycorp subsidiary sold down its equity investment in a niobium operation in Brazil, from 40 percent to 35 percent for pre-tax proceeds of \$31 million in cash. We sold our needle coke business for \$25 million in cash plus \$22 million in working capital. We also received pre-tax proceeds of \$30 million from the sale of other oil and gas properties, \$20 million from the sale of other miscellaneous assets and \$10 million from the sale of real estate properties. Pre-tax proceeds from asset sales were \$278 million for the six months ended June 30, 2004. We received net proceeds of \$176 million from the sale of certain of our mineral fee lands in the United States, \$60 million from the sale of our rights and interests in the Sarulla geothermal project in Indonesia and \$19 million from the sale of the Cal Ven Pipeline system in Canada. We also received approximately

another \$23 million from the sale of various properties, primarily in the Gulf of Mexico. Long-term Debt Unocal's total consolidated debt, including current maturities, was \$2.54 billion at June 30, 2005, compared with \$3.06 billion at the end of 2004. In the first six months of 2005, we paid a combination of cash and Unocal common stock to retire the \$242 million outstanding balance of the 6-1/4% convertible junior subordinated debentures (see note 15 for further detail). We retired \$85 million in 7.20 percent notes that matured in the first six months of 2005. We paid \$77 million as full payment under the revolving portion of our Canadian dollar-denominated credit agreement, which we terminated in July 2005. In addition, we paid \$76 million in medium term notes that matured in the first six months of 2005. Finally, we paid \$26 million related to a limited recourse loan for our West Seno project in Indonesia and \$9 million related to a non-recourse loan from one of our Geothermal segment subsidiaries. Other Financing Activities In 2005, we received \$120 million from the issuance of 3,555,676 shares of our common stock related to the exercise of existing stock options. This compared to \$94 million from the issuance of 3,986,394 shares for the six months ended June 30, 2004. -45- Off-Balance Sheet Arrangements - Sales of Accounts Receivables Through a bankruptcy remote wholly-owned subsidiary, Unocal Receivables Corporation ("URC"), we had a sales agreement with an outside unrelated party that provided for the sale of up to \$125 million of an undivided interest in domestic crude oil and natural gas trade receivables. We used this program as a low cost and readily available source of working capital. Details of this arrangement are provided in note 11 to the consolidated financial statements in Item 8 of our 2004 10-K. We terminated this program effective April 15, 2005. Environmental Matters We are committed to operating our business in a manner that is environmentally responsible. This commitment is fundamental to our core values. As part of this commitment, we have procedures in place to audit and monitor our environmental performance. In addition, we have implemented programs to identify and address environmental risks throughout our company. Probable costs associated with identified and reasonably estimable environmental obligations have been accrued in a reserve for such obligations. Accruals are based on developments to date, our estimates of the outcomes of these matters and our experience in addressing these matters. As the scope of the liabilities becomes better defined, there will be changes in the estimates of future costs, which could have a material effect on our future results of operations, financial condition or liquidity. At June 30, 2005, our reserves for environmental remediation obligations totaled \$239 million, of which \$112 million was included in current liabilities. During the first six months of 2005, cash payments of \$48 million were applied against the reserves and \$43 million was added to the reserves. We may also incur additional liabilities at sites where remediation liabilities are probable but future environmental costs are not presently reasonably estimable because the sites have not been assessed or the assessments have not advanced to stages where costs are reasonably estimable. At those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, we estimate that we could incur possible additional remediation costs aggregating approximately \$235 million. The reserve amounts and estimated possible additional costs are grouped into the following four categories: At June 30, 2005 ----- Possible Millions of dollars Reserve Additional Costs ----- Superfund and similar sites \$ 12 \$ 15 Active Company facilities 25 35 Company facilities sold with retained liabilities and former Company-operated sites 100 80 Inactive or closed Company facilities 102 105 ----- Total \$ 239 \$ 235

===== See notes 16 and 17 to the consolidated financial statements in Item 1 of this report for additional information on environmental related matters. In the first six months of 2005, we recorded provisions of \$25 million for the "Company facilities sold with retained liabilities and former Company-operated sites" category. These provisions were primarily for sites that may have been contaminated by our former operations. The provisions were based on new and revised cost estimates that we identified during 2005 for the remediation of approximately 125 service station, bulk plant and terminal sites and for the assessment and remediation of oil and gas fields in Central California. During the first six months of 2005, we recorded provisions of \$15 million for sites in the "Inactive or closed Company facilities" category, primarily for the Guadalupe oil field site on the central California coast. Soil at this site has been contaminated with diluent, a kerosene-like additive used in the field's former operations. The provision includes revised estimated costs for remediation work that is required by the cleanup and abatement order for the site. The required remediation work has become better defined through ongoing and continuing meetings and negotiations with the -46- regulatory agencies. This work includes studies, operation and maintenance of remedial systems, restoration, and regulatory agency oversight and permitting procedures. In the first six months of 2005, our estimated

possible additional remediation costs increased by \$10 million for the "Company facilities sold with retained liabilities and former Company-operated sites" category. This increase was primarily for the cost of remediation that may be needed at oil and gas fields in Central California that we formerly operated. Our estimated possible additional costs for the "Inactive or closed Company facilities" category of sites increased by \$10 million during the first six months of 2005. The increase was primarily for the Guadalupe oil field site. Higher estimated costs for remediation work may be incurred for groundwater monitoring, operation and maintenance of remedial systems, restoration, and regulatory agency oversight and permitting procedures. These revised estimates are based on ongoing and continuing meetings and negotiations with the regulatory agencies. Litigation and Other Contingencies We are also subject to contingent liabilities for existing and potential claims, lawsuits and other proceedings and tax and other matters. For a more detailed discussion on these matters, see Item 3 in Part I and note 23 to the consolidated financial statements included in Item 8 of Part II of our 2004 Form 10-K and Item 1 in Part II and note 17 to the interim financial statements included in Item 1 of Part I of this report.

OPERATIONS OUTLOOK The following operations outlook is based upon our current expectations and beliefs. These statements are subject to a number of known and unknown risks and uncertainties that could cause actual results to differ materially from those described, including our pending merger with Chevron and the effect on us if the merger is not consummated. Please see the cautionary statement under "Forward-Looking Statements" on page iii of this report and the "Risk Factors" in Item 7 of Part II of our 2004 10-K. This outlook discusses our current expectations regarding certain important operational activities for the remainder of 2005 and for other future time periods. It is not intended to be a complete discussion of all future operational activities. Our profitability will continue to be significantly affected by crude oil and natural gas commodity prices. We expect energy prices to remain volatile for the remainder of 2005 due to a variety of fundamental and market perception factors including variability of the weather on a year-to-year basis, worldwide demand, crude oil and natural gas inventory levels, production quotas set by OPEC, current and future worldwide political instability, worldwide security and other factors. To seek to mitigate some of that volatility, we have secured fixed price "hedges" on portions of our anticipated future natural gas and crude oil production. From July 2005 through December 2006, we have hedge contracts in place equivalent to approximately 35 percent of our anticipated U.S. Lower 48 production. The average hedge prices through 2006 are approximately \$59.00 for crude oil and \$7.90 for natural gas. In addition, there are also hedges in place from 2007 through mid-2008 ranging from 10 to 20 percent of anticipated U.S. Lower 48 production. In the first six months of 2005, we initiated production from all five major projects in our 2005 development pipeline - Mad Dog in the deepwater Gulf of Mexico, Phase 1 of the ACG crude oil project in the Azerbaijan sector of the Caspian Sea, the Moulavi Bazar field in Bangladesh, the K-2 field in the deepwater Gulf of Mexico and Phase 2 of the Thailand crude oil project.

Exploration and Production - North America United States o The Mad Dog field in the Gulf of Mexico, operated by BP, began production in January 2005. The K-2 field in the Gulf of Mexico, operated by Eni, began production in May 2005. The estimate of our net production for both the Mad Dog field and K-2 fields combined is expected to average about 5 MBOE/d to 7 MBOE/d in the third quarter of 2005, rising to an average of 8 MBOE/d to 11 MBOE/d in the fourth quarter of 2005. We have a 15.6 percent working interest in the Mad Dog field and a 12.5 percent working interest in the K-2 field. -47- o Our deepwater Gulf of Mexico exploration and appraisal program continues in 2005. We are currently drilling the Knotty Head well, located in Green Canyon Block 512. We are also currently participating in drilling a well in Green Canyon Block 821, a follow-up on the Puma discovery in Green Canyon Block 823, and Mad Dog Deep, a Paleogene test, in Green Canyon Block 826, both operated by BP.

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

Exploration and Production - International Asia Thailand: o Start up of the Phase 2 development of the Thailand crude oil project commenced in June 2005 with production expected to ramp up to peak capacity by late third quarter. The average net production rate from Phase 2 is expected to be between 7 MBOE/d and 9 MBOE/d in the third quarter of 2005 and between 9 MBOE/d and 11 MBOE/d in the fourth quarter of 2005. o Thailand's electricity market is expected to continue growing in 2005. Additional supplies of natural gas to meet that growth have been constrained by pipeline capacity. De-bottlenecking activities on the two existing pipelines in the Gulf of Thailand should allow us an opportunity for increased production in 2005, prior to the expected completion of a third pipeline in 2006.

Indonesia: o Development engineering and planning is continuing for multiple oil and gas discoveries in the deepwater Kutei Basin. The development strategy is to install two new deepwater production

processing hubs, one at Gendalo and one at Gehem. These hubs will process oil and gas production for multiple satellite developments. The initial plans of development for both hubs are currently being prepared for submission to partners and the Government of Indonesia in 2005. o We are also continuing to work on our evaluation for development feasibility at the Sadewa field, which is a candidate for early natural gas development because of its proximity to the shelf. Concept selection work has been completed and detailed design work has begun. The development concept is a natural gas and crude oil development from a shallow-water platform with extended reach wells towards targets in deep water. Bangladesh: o First production from the Moulavi Bazar field began in March 2005. This new field is expected to increase our net average production over 2004 levels in the country by 14 MBOE/d to 17 MBOE/d in the third quarter of 2005. This production outlook reflects higher volumes due partially to an increase in cost recovery that we expect to receive from the Jalalabad field because of new production from the Moulavi Bazar field. We anticipate the net average incremental production over 2004 levels in the fourth quarter of 2005 to be 9 MBOE/d to 15 MBOE/d due to the completion of cost recovery. o Work continues to progress at the Bibiyana field which is planned to be developed in stages to provide Bangladesh with natural gas resources in the short, medium and long-term time frames. We currently expect first production by the end of 2006. -48- Other International Azerbaijan: o First production from Phase 1 of the ACG crude oil project began in the first quarter of 2005. Phase 1 is expected to deliver net average production of 11 MBOE/d to 13 MBOE/d in the third quarter of 2005 and 14 MBOE/d to 16 MBOE/d in the fourth quarter of 2005. Chirag will continue to average more than 12 MBOE/d net in the second half of 2005. Development on Phases 2 and 3 of the ACG crude oil project will continue in 2005. We have a 10.28 percent working interest in the AIOC project. Turkey/Georgia: o We entered into a farm-in agreement for acreage held by BP in the Turkey and Georgia sections of the Eastern Black Sea. The geologic setting of the exploration acreage is similar to the ACG field in Azerbaijan but at deeper water depths (2100 to 5500 feet). Subject to government approvals, we will acquire a 25 percent working interest in Turkish Block 3534 and a 10 percent working interest in Georgia Blocks APC-IIA, IIB and III. BP plans to spud an exploration well on one of the prospects in Turkey in the third quarter of 2005. We expect our share of capital expenditures for the Black Sea venture to be approximately \$50 million in 2005. Midstream and Marketing In parallel with the ACG crude oil project, the BTC crude oil pipeline will start to line-fill portions of the pipeline through Georgia and Turkey in the second half of 2005. The BTC pipeline will transport the crude oil from the ACG crude oil project to the Turkish port of Ceyhan and will have a capacity of 1 million Bbl/d. Our interest in this pipeline is 8.9 percent. FUTURE ACCOUNTING CHANGES See note 2 to the consolidated financial statements for information about recent accounting pronouncements. -49- ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. We are exposed to market risks, which may give rise to losses from adverse changes in market prices and rates. The primary market risks to which we are exposed are: (1) commodity prices, (2) interest rates and (3) foreign currency exchange rates. As part of our overall risk management strategies, we use derivative financial instruments to manage and seek to reduce risks associated with these factors. We also trade hydrocarbon derivative instruments, such as futures contracts, swaps and options to exploit anticipated opportunities arising from commodity price fluctuations. To the extent that we engage in hedging activities to seek to protect ourselves from commodity price volatility, we may be prevented from realizing the benefits of price increases above the levels of the hedges. In addition, speculative trading in hydrocarbon commodities and derivative instruments in connection with our risk management activities subjects us to additional risk. We determine the fair values of our derivative financial instruments primarily based upon market quotes of exchange traded instruments. Most futures and options contracts are valued based upon direct exchange quotes or industry published price indices. Some instruments with longer maturity periods require financial modeling to accommodate calculations beyond the horizons of available exchange quotes. These models calculate values for outer periods using current exchange quotes (i.e., forward curve) and assumptions regarding interest rates, commodity and interest rate volatility and, in some cases, foreign currency exchange rates. While we feel that current exchange quotes and assumptions regarding interest rates and volatilities are appropriate factors to measure the fair value of our longer termed derivative instruments, other pricing assumptions or methodologies may lead to materially different results in some instances. Commodity Price Risk - We are a producer, purchaser, marketer and trader of certain hydrocarbon commodities such as crude oil and condensate, natural gas and refined products and are subject to the associated price risks. We use hydrocarbon price-sensitive derivative instruments ("hydrocarbon derivatives"), such as futures contracts, swaps, collars and options, to mitigate our overall exposure to fluctuations in hydrocarbon commodity prices. We may also enter into hydrocarbon derivatives to hedge contractual delivery commitments and

future crude oil and natural gas production against price exposure. We also actively trade hydrocarbon derivatives, primarily exchange regulated futures and options contracts, subject to internal policy limitations. We use a variance-covariance value at risk model to assess the market risk of our hydrocarbon derivatives. Value at risk represents the potential loss in fair value we would experience on our hydrocarbon derivatives, as a result of commodity price changes using calculated volatilities and correlations over a specified time period with a given confidence level. Our risk model is based upon current market data and uses a three-day time interval with a 97.5 percent confidence level. The model includes offsetting physical positions for any existing hydrocarbon derivatives related to our fixed price pre-paid crude oil and pre-paid natural gas sales. The model also includes our net interests in our subsidiaries' crude oil and natural gas hydrocarbon derivatives and forward sales contracts. Based upon our risk model, the value at risk related to hydrocarbon derivatives held for hedging purposes was \$11 million at June 30, 2005. Value at risk related to hydrocarbon derivatives held for non-hedging purposes was immaterial at June 30, 2005. See "Hydrocarbon Derivatives Tables." Interest Rate Risk - From time to time, we temporarily invest our excess cash in short-term interest-bearing securities issued by high-quality issuers. Our policies limit the amount of investment in securities of any one financial institution. Due to the short time the investments are outstanding and their general liquidity, these instruments are classified as cash equivalents in the consolidated balance sheet and do not represent a material interest rate risk to us. Our primary market risk exposure to changes in interest rates relates to our long-term debt obligations. We manage our exposure to changing interest rates principally with a combination of fixed and floating rate debt. Interest rate risk sensitive derivative financial instruments, such as swaps or options, may also be used depending upon market conditions. We evaluated the potential effect that near term changes in interest rates would have had on the fair value of our interest rate risk sensitive financial instruments at June 30, 2005. Assuming a ten percent decrease in our weighted average borrowing costs at June 30, 2005, the potential increase in the fair value of our debt obligations and associated interest rate derivative instruments, including the debt obligations and associated interest rate derivative instruments of our subsidiaries, would have been \$83 million at June 30, 2005. -50- Foreign Exchange Rate Risk - We conduct business in various parts of the world and in various foreign currencies. To limit our foreign currency exchange rate risk related to operating income, foreign sales agreements generally contain price provisions designed to insulate our sales revenues against adverse foreign currency exchange rates. In most countries, energy products are valued and sold in U.S. dollars and foreign currency operating cost exposures have not been significant. In other countries, we are paid for product deliveries in local currencies but at prices indexed to the U.S. dollar. These funds, less amounts retained for operating costs, are converted to U.S. dollars as soon as practicable. Our Canadian subsidiaries are paid in Canadian dollars for their crude oil and natural gas sales. From time to time, we may purchase foreign currency options or enter into foreign currency swap or foreign currency forward contracts to limit the exposure related to our foreign currency debt or other obligations. At June 30, 2005, we had various foreign currency forward contracts outstanding related to operations in Thailand. We evaluated the effect that near term changes in foreign exchange rates would have had on the fair value of our combined foreign currency position related to our outstanding foreign currency swaps, forward contracts and foreign-currency denominated debt. Assuming an adverse change of ten percent in foreign exchange rates at June 30, 2005, the potential decrease in fair value of the foreign currency swaps, foreign currency forward contracts and foreign-currency denominated debt for us would have been \$25 million at June 30, 2005. Hydrocarbon Derivatives Tables - The following tables set forth the future volumes and price ranges of hydrocarbon derivatives we held at June 30, 2005, along with the fair values of those instruments. Open Hydrocarbon Hedging Derivative Instruments (a) (Thousands of dollars) Fair Value Asset 2005 2006 2007 Thereafter (Liability) (b)

----- Natural Gas
Futures Positions Volume (MMBtu) 170,000 - - - \$ 158 Average price, per MMBtu \$ 6.65 Volume (MMBtu)
(8,830,000) - - - \$ 1,243 Average price, per MMBtu \$ 7.14

----- Natural Gas
Swap Positions Pay fixed price Volume (MMBtu) 6,206,900 9,508,000 7,218,000 7,241,000 \$ 139,350 Average swap
price, per MMBtu \$ 4.13 \$ 3.46 \$ 2.47 \$ 2.52 Receive fixed price Volume (MMBtu) 5,340,000 - - - \$ (5,926) Average
swap price, per MMBtu \$ 6.29

----- Natural Gas
Basis Swap Positions Volume (MMBtu) 1,220,000 - - - \$ 109 Average price received, per MMBtu \$ 6.59 Average
price paid, per MMBtu \$ 6.44

----- Crude Oil
Futures Positions Volume (Bbls) 70,000 - - - \$ (556) Average price, per Bbl \$ 56.05 Volume (Bbls) (1,648,000) - - - \$ (10,438) Average price, per Bbl \$ 52.72

----- (a) Futures positions reflect long (short) volumes. (b) Net claims against counterparties with non-investment grade credit ratings are immaterial. -51- Open Hydrocarbon Non-Hedging Derivative Instruments (a) (Thousands of dollars Fair Value Asset 2005 2006 2007 (Liability) (b)

----- Natural Gas
Futures Positions Volume (MMBtu) 1,760,000 - 300,000 \$ 212 Average price, per MMBtu \$ 7.13 \$ 7.77 Volume (MMBtu) (1,560,000) - - \$ 46 Average price, per MMBtu \$ 7.02

----- Natural Gas
Swap Positions Pay fixed price Volume (MMBtu) 2,705,000 - 300,000 \$ 520 Average swap price, per MMBtu \$ 7.01 \$ 7.76 Receive fixed price Volume (MMBtu) 1,852,500 - 600,000 \$ (1,174) Average swap price, per MMBtu \$ 6.90 \$ 7.74 ----- Natural Gas
Gas Spread Swap Positions Volume (MMBtu) 24,970,000 7,225,000 - \$ (8,854) Average price paid, per MMBtu \$ 0.46 \$ 0.72 - Volume (MMBtu) 25,120,000 7,835,000 900,000 \$ 9,074 Average price received, per MMBtu \$ 0.46 \$ 0.77 \$ 1.26 -----

Natural Gas Option (Listed & OTC) Call Volume -Buy-(MMBtu) 5,500,000 - - \$ (549) Average Call price \$ 7.97 Call Volume -Sell-(MMBtu) 7,320,000 - - \$ 996 Average Call price \$ 7.92 Put Volume -Buy-(MMBtu) 1,480,000 1,860,000 - \$ (393) Average Put Price \$ 5.49 4.75 Put Volume -Sell-(MMBtu) 6,280,000 1,860,000 - \$ 595 Average Put Price \$ 4.71 \$ 4.75

----- Crude Oil
Futures Positions Volume (Bbls) 4,340,000 275,000 - \$ 52,706 Average price, per Bbl \$ 49.92 \$ 53.87 Volume (Bbls) (4,040,000) (275,000) - \$(52,261) Average price, per Bbl \$ 49.06 \$ 52.09

----- Crude Oil
Option (Listed & OTC) Call Volumes -Sell-(Bbls) - - - \$ 6 Average price, per Bbl Put Volume -Buy-(Bbls) - - - \$ (131) Average price, per Bbl Put Volume -Sell-(Bbls) - - - \$ 101 Average price, per Bbl

----- Crude Oil
Swap Positions Pay fixed price Volume (Bbls) 2,860,000 375,000 - \$ 68,042 Average swap price, per Bbl \$ 34.33 \$ 39.29 Receive fixed price Volume (Bbls) 3,210,000 475,000 - \$(77,290) Average swap price, per Bbl \$ 33.26 \$ 37.30

----- (a) Futures positions reflect long (short) volumes. (b) Net claims against counterparties with non-investment grade credit ratings are immaterial. (c) Prices quoted from the New York Mercantile Exchange (NYMEX) and Inside FERC Gas Report (IFERC). -52- ITEM 4. CONTROLS AND PROCEDURES Disclosure Controls and Procedures We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our reports under the Securities Exchange Act of 1934 is processed, recorded, summarized and reported within the time periods specified in the SEC's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures. As required by SEC Rule 13a-15(b), we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on the foregoing, our Chief Executive Officer and Chief Financial Officer concluded, as of that time, that our disclosure controls and procedures were effective at the reasonable assurance level. Internal Control over Financial Reporting There was no change in our internal control over financial reporting that occurred during the three months ended June 30, 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control processes from time to time in the future. -53- PART II - OTHER INFORMATION
ITEM 1. LEGAL PROCEEDINGS. See the information with respect to certain legal proceedings pending or

threatened against Unocal previously reported in Item 3 of our 2004 10-K and in Item 1 of Part II of our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2005. The following is incorporated by reference: the information regarding the environmental remediation reserve and possible additional remediation costs in notes 16 and 17 to the consolidated financial statements in Item 1 of Part I of this report; the discussion of such amounts in the Environmental Matters section of Management's Discussion and Analysis in Item 2 of Part I; and the information regarding certain litigation and claims, tax matters and other contingent liabilities in note 17 to the consolidated financial statements in Item 1 of Part I of this report. **ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.** Unocal Purchases of Equity Securities The following table shows information regarding repurchases we made of our shares of common stock during the second quarter of 2005:

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

----- 1. During the second quarter, we cancelled 7,951 shares repurchased for the payment of withholding taxes due on restricted stock that vested under various employee restricted stock plans. During the second quarter, we purchased 42,646 shares in the open market and distributed these shares to employee participants in Unocal's savings plans, which are defined contribution plans with 401(k) features.

2. At June 30, 2005, the total authorized common stock repurchase program limit authorized by our board of directors was \$459 million. There is no expiration date to this repurchase program. No purchases are currently planned under this program. 3. In 2004, our board of directors authorized the repurchase from time to time of shares of our common stock in order to offset the net number of shares of common stock issued by us upon the exercise or granting, as the case may be, of existing or subsequently issued stock options or shares of our restricted common stock. There is no expiration date to the repurchase program. The board authorized management to determine whether, and when, to effect any repurchases under this program and did not limit the aggregate dollar amount for any such repurchases. No purchases are currently planned under this program. -54- **ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.** Our 2005 annual meeting of stockholders was held on May 23, 2005. The following actions were taken by our stockholders at the annual meeting, for which proxies were solicited pursuant to Regulation 14 under the Securities Exchange Act of 1934: 1. The four nominees proposed by our board of directors were elected as directors by the following votes for three-year terms expiring at the 2008 annual meeting of stockholders, or until their successors are duly elected and qualified or their earlier resignation, if applicable: Name Votes For Votes Withheld

Craig Arnold 235,858,287 7,019,783 James W. Crownover 235,981,853 6,896,217 Donald B. Rice 235,583,875 7,294,195 Mark A. Suwyn 235,879,608 6,998,462 2. A proposal to ratify the appointment of PricewaterhouseCoopers LLP as Unocal's independent auditors for 2005 was passed by a vote of 238,759,878 for (98.34%) versus 2,456,889 against (1.01%) and 1,571,304 abstentions (0.65%). There were 90,000 broker non-votes. 3. A stockholder proposal requiring that the Chairman of the Board be an independent director who has not previously served as an executive officer of Unocal failed to pass, with a vote of 23,550,182 for (11.29%) versus 182,821,266 against (87.66%) and 2,216,143 abstentions (1.05%). There were 34,290,479 broker non-votes. -55- **ITEM 6. EXHIBITS.** The following exhibits are filed or furnished, as applicable, as part of this report: 2.1 Amendment No. 1 to the Agreement and Plan of Merger, dated as of July 19, 2005, among Unocal Corporation, Chevron Corporation and Blue Merger Sub Inc. (incorporated by reference to Exhibit 2.1 to Unocal's Current Report on Form 8-K dated July 19, 2005, and filed July 22, 2005, File No. 1-8483). 2.2 Waiver Letter from Chevron Corporation, dated June 23, 2005 (incorporated by reference to Exhibit 99.2 to Unocal's Current Report on Form 8-K dated June 23, 2005, and filed June 24, 2005, File No. 1-8483). 10.1 Share Purchase Agreement dated July 8, 2005 between Unocal Canada Limited, Unocal Canada Alberta Hub Limited, Unocal Corporation, Pogo Canada, ULC and Pogo Producing Company (incorporated by reference to Exhibit 10.1 to Unocal's Current Report on Form 8-K dated July 12, 2005, and filed July 14, 2005, File No. 1-8483). 10.2 Unocal Deferred Compensation Plan of 2005 (incorporated by reference to Exhibit 10.1 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483). 10.3 2004 Directors' Deferred Compensation and Restricted Stock Unit Award Plan (as amended and restated effective as of January 1,

2005) (incorporated by reference to Exhibit 10.2 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483). 10.4 Unocal Nonqualified Retirement Plan A1 (as amended and restated effective July 14, 2005) (incorporated by reference to Exhibit 10.3 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483). 10.5 Unocal Nonqualified Retirement Plan B1 (as amended and restated effective July 14, 2005) (incorporated by reference to Exhibit 10.4 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483). 10.6 Unocal Nonqualified Retirement Plan C1 (as amended and restated effective July 14, 2005) (incorporated by reference to Exhibit 10.5 to Unocal's Current Report on Form 8-K dated July 14, 2005, and filed July 15, 2005, File No. 1-8483). 31.1 Chief Executive Officer certifications pursuant to Exchange Act Rule 13a-14(a). 31.2 Chief Financial Officer certifications pursuant to Exchange Act Rule 13a-14(a). 32 Furnished Certifications Pursuant to Exchange Act Rule 13a-14(b). Copies of exhibits will be furnished upon request. Requests should be addressed to the Corporate Secretary and mailed to the address set forth on the cover page to this report. -56- SIGNATURE Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. UNOCAL CORPORATION (Registrant) Dated: August 4, 2005 By: /s/JOHN A. BRIFFETT ----- John A. Briffett Vice President and Comptroller (Duly Authorized Officer and Principal Accounting Officer) -57-