Union Oil Company of California

2141 Rosecrans Ave., Suite 4000
El Segundo, CA 90245

UNION 76

March 31, 2003

U.S. Nuclear Regulatory Commission
Mail Stop T7 F27
Washington, DC 20555

ATTN: Larry W. Camper

RE: FINANCIAL ASSURANCE
FOR LICENSE NO.
SMB - 1393 AND SMB - 1408

Dear Mr. Camper

Enclosed, please find the following documents of financial assurance submitted on behalf of our subsidiary, Molycorp, Inc.:

6. Letter from Chief Financial Officer (CFO) of the parent company, Union Oil Company of California, including the financial test alternative II,

7. Letter from Chief Executive Officer (CEO) of licensee, Molycorp, Inc. Please note that the amended wording in paragraph 1 "this letter is in support of this firm's use of the parent company guarantee and associated financial test to demonstrate financial assurance, as specified in 10 CFR Part 40" has been approved by Mr. Tom Fredrichs of the Nuclear Regulatory Commission (NRC).

8. Auditor's special report confirming CFO Letter and reconciling amounts in the CFO letter with parent company's financial statements

9. Parent company's audited financial statements for the most recent fiscal year, including the auditor's opinion on the financial statements

10. Parent company guarantee for decommissioning activities

Please acknowledge receipt of this letter by signing and returning the attached copy of this letter in the envelope provided.

Should you have any questions, please call me at (714-577-1604.

Sincerely,

Fred P. Dezwart
Manager of Real Estate Accounting
Real Estate Remediation Services

FPD
Enclosures

Bcc: R. Cherniske
M. Dixon
S. Ramones

Union Oil Company of California
2141 Rosecrans Ave., Suite 4000
El Segundo, CA 90245

UNION 76

March 31, 2003

U.S. Nuclear Regulatory
Commission
Mail Stop T7 F27
Washington, DC 20555

ATTN: Larry W. Camper

RE: CHIEF FINANCIAL OFFICER
LETTER FOR LICENSE NO.
SMB - 1393 AND SMB - 1408

Dear Mr. Camper

I am the chief financial officer of Union Oil Company of California, 2141 Rosecrans Avenue, Suite 4000 El Segundo, CA 90245, a corporation. This letter is in support of this firm's use of the financial test to demonstrate financial assurance, as specified in 10 CFR Part 40.

This firm guarantees, through the parent company guarantee submitted to demonstrate compliance under 10 CFR Part 40, the decommissioning of the following facilities owned or operated by subsidiaries of this firm. The current cost estimates or certified amounts for decommissioning, so guaranteed, are shown for each facility:

Name of Facility	License Number	Location of Facility	Certified Amounts Or Current Cost Estimates
Molycorp, Inc.	SMB - 1393	300 Caldwell Avenue Washington, PA 15301	$30,265,000
Molycorp, Inc.	SMB - 1408	350 N. Sherman Avenue York, PA 17402	$3,825,000

This firm is not required to file a Form 10-K with the U.S. Securities and Exchange Commission for the latest fiscal year.

This fiscal year of this firm ends on December 31. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements and footnotes for the latest completed fiscal year, ended December 31, 2002. A copy of this firm's most recent financial statements is enclosed.

PARENT COMPANY GUARANTEE FINANCIAL TEST II

1. Current decommissioning cost estimates or certified amounts
   a. Decommissioning amounts covered by this parent company guarantee — $34,090,000
   b. All decommissioning amounts covered by other NRC or Agreement State parent company guarantees or self-guarantees — $ 0
   c. All amounts covered by parent company guarantees, self-guarantees, or financial tests of other Federal or State agencies (e.g., EPA) — $466,623,784

   TOTAL — $500,713,784

2. Current bond rating of most recent unsecured issuance of this firm
   Rating BBB+
   Name of rating service Standard & Poor's

3. Date of issuance of bond October 3, 2002

4. Date of maturity of bond October 1, 2012

*5. Tangible net worth** (if any portion of estimates for decommissioning is included in total liabilities on your firm's financial statements, you may add the amount of that portion to this line) — $3,664,000,000

*6. Total assets in United States (required only if less than 90 percent of firm's assets are located in the United States) — $5,107,000,000

		Yes	No
7.	Is line 5 at least $10 million?	X	
8.	Is line 5 at least 6 times line 1?	X	
9.	Are at least 90 percent of firm's assets located in the United States? If not, complete line 10.		X
10.	Is line 6 at least 6 times line 1?	X	
11.	Is the rating specified on line 2 "BBB" or better (if issued by Standard & Poor's) or "Baa" or better (if issued by Moody's)?	X	

* Denotes figures derived from financial statements.
** Tangible net worth is defined as net worth minus goodwill, patents, trademarks, and copyrights.

I hereby certify that the content of this letter is true and correct to the best of my knowledge.

Signature___________________

Name – Terry G. Dallas

Title – Chief Financial Officer

Date – March 31, 2003

Molycorp, Inc.
376 South Valencia Avenue
Brea, California 92823

Molycorp

March 24, 2003

Mr. Larry W. Camper
U.S. Nuclear Regulatory Commission
Mail Stop T7 F27
Washington, DC 20555

RE: CHIEF EXECUTIVE OFFICER LETTER FOR
LICENSE NO. SMB - 1393 and SMB - 1408

Dear Mr. Camper:

I am the chief executive officer of Molycorp, Inc. 376 S. Valencia Brea, CA 92823, a Delaware corporation. This letter is in support of this firm's use of the parent company guarantee and associated financial test to demonstrate financial assurance, as specified in 10 CFR Part 40.

I hereby certify that Molycorp, Inc. is currently a going concern, and that it possesses negative tangible net worth in the amount of $60,135,430.

This firm is not required to file a Form 10-K with the U.S. Securities and Exchange Commission for the latest fiscal year. This fiscal year of this firm ends on December 31.

I hereby certify that the content of this letter is true and correct to the best of my knowledge.

Very truly yours,

Mark A. Smith

Mark A. Smith
Chief Executive Officer

PARENT COMPANY GUARANTEE FOR
DECOMMISSIONING ACTIVITIES,
LICENSE NO. SMB - 1393 and SMB - 1408

Guarantee made this March 31, 2003 by Union Oil Company of California, a corporation organized under the laws of the State of California, herein referred to as "guarantor," to the U.S. Nuclear Regulatory Commission (NRC), beneficiary, on behalf of our subsidiary Molycorp, Inc., of 300 Caldwell Avenue, Washington, PA 15301 and Molycorp, Inc. of 350 North Sherman Avenue, York, PA 17402.

Recitals

1. The guarantor has full authority and capacity to enter into this guarantee under its bylaws, articles of incorporation, and the laws of the State of California, its State of incorporation. Guarantor has approval from its Board of Directors to enter into this guarantee.

2. This guarantee is being issued to comply with regulations issued by the NRC, an agency of the U.S. Government, pursuant to the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act of 1974. NRC has promulgated regulations in Title 10,Chapter I of the Code of Federal Regulations, Part 40 which require that a holder of, or an applicant for, a materials license issued pursuant to 10CFR Part 40 provide assurance that funds will be available when needed for required decommissioning activities.

3. The guarantee is issued to provide financial assurance for decommissioning activities for Molycorp, Inc.'s facilities located at 300 Caldwell Avenue, Washington, PA 15301, License No. SMB – 1393 (hereinafter referred to as the "Molycorp Washington Facility") and at 350 North Sherman Avenue, York, PA 17402, License No. SMB – 1408 (hereinafter referred to as the "Molycorp York Facility") as required by 10 CFR Part 40. The decommissioning costs for these activities are as follows:

   Molycorp Washington Facility
   License No. SMB – 1393
   Decommissioning costs guaranteed - $30,265,000

   Molycorp York Facility
   License No. SMB – 1408
   Decommissioning costs guaranteed - $3,825,000

4. The guarantor meets or exceeds the following financial test criteria of parent company guarantee financial test II and agrees to comply with all notification requirements as specified in 10 CFR Part 40 and Appendix A to 10 CFR Part 30.

   The guarantor meets one of the following two financial tests:

   (a)(i) Two of the following three ratios: a ratio of total liabilities to net worth less than 2.0; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; and a ratio of current assets to current liabilities greater than 1.5; and (a)(ii) Net working capital and tangible net worth each at least six times the costs covered by financial tests; and

(a)(iii) Tangible net worth of at least $10 million; and

(a)(iv) Assets located in the United States amounting to at least 90 percent of total assets or at least six times the costs covered by financial tests.

OR

(b)(i) A current rating for its most recent bond issuance of AAA, AA, A, or BBB as issued by Standard & Poor's, or Aaa, Aa, A or Baa as issued by Moody's; and

(b)(ii) Tangible net worth at least six times the costs covered by financial tests; and

(b)(iii) Tangible net worth of at least $10 million; and

(b)(iv) Assets located in the United States amounting to at least 90 percent of total assets or at least six times the costs covered by financial tests.

5. The guarantor has majority control of the voting stock for the following licensees covered by this guarantee:

   Molycorp, Inc.

6. Decommissioning activities as used below refer to the activities required by 10 CFR Part 40 for decommissioning of the facilities identified above.

7. For value received from Molycorp, Inc., and pursuant to the guarantor's authority to enter into this guarantee, the guarantor guarantees to the NRC that if the licensee fails to perform the required decommissioning activities, as required by License No. SMB –1393 and License No. SMB - 1408, the guarantor shall

   (a) carry out the required activities, or

   (b) set up a trust fund in favor of the above identified beneficiary in the amount of the current cost estimates for these activities.

8. The guarantor agrees to submit revised financial statements, financial test data, and an auditor's special report and reconciling schedule annually within 90 days of the close of the parent guarantor's fiscal year.

9. The guarantor agrees that if, at the end of any fiscal year before termination of this guarantee, it fails to meet the financial test criteria, the licensee shall send within 90 days of the end of the fiscal year, by certified mail, notice to the NRC that the licensee intends to provide alternative financial assurance as specified in 10 CFR Part 40. Within 120 days after the end of the fiscal year, the guarantor shall establish such financial assurance if the Molycorp, Inc. has not done so.

10. The guarantor also agrees to notify the beneficiary promptly if the ownership of the

licensee or the parent firm is transferred and to maintain this guarantee until the new parent firm or the licensee provides alternative financial assurance acceptable to the beneficiary.

11. The guarantor agrees that if it determines, at any time other than as described in Recital 9, that it no longer meets the financial test criteria or it is disallowed from continuing as a guarantor, it shall establish alternative financial assurance as specified in 10 CFR Part 30, 40, 70, or 72, as applicable, within 30 days, in the name of Molycorp, Inc. unless Molycorp, Inc. has done so.

12. The guarantor as well as its successors and assigns agree to remain bound jointly and severally under this guarantee notwithstanding any or all of the following: amendment or modification of license or NRC-approved decommissioning funding plan for that facility, the extension or reduction of the time of performance of required activities, or any other modification or alteration of an obligation of the licensee pursuant to 10 CFR Part 40.

13. The guarantor agrees that all bound parties shall be jointly and severally liable for all litigation costs incurred by the beneficiary, NRC, in any successful effort to enforce the agreement against the guarantor.

14. The guarantor agrees to remain bound under this guarantee for as long as Molycorp, Inc. must comply with the applicable financial assurance requirements of 10 CFR Part 40, for the previously listed facilities, except that the guarantor may cancel this guarantee by sending notice by certified mail to the NRC and to Molycorp, Inc., such cancellation to become effective no earlier than 120 days after receipt of such notice by both the NRC and Molycorp, Inc. as evidenced by the return receipts.

15. The guarantor agrees that if Molycorp, Inc. fails to provide alternative financial assurance as specified in 10 CFR Part 40, as applicable, and obtain written approval of such assurance from the NRC within 90 days after a notice of cancellation by the guarantor is received by both the NRC and Molycorp, Inc. from the guarantor, the guarantor shall provide such alternative financial assurance in the name of Molycorp, Inc. or make full payment under the guarantee.

16. The guarantor expressly waives notice of acceptance of this guarantee by the NRC or by Molycorp, Inc.. The guarantor also expressly waives notice of amendments or modifications of the decommissioning requirements and of amendments or modifications of the license.

17. If the guarantor files financial reports with the U.S. Securities and Exchange Commission, then it shall promptly submit them to the NRC during each year in which this guarantee is in effect.

I hereby certify that this guarantee is true and correct to the best of my knowledge.

Effective date: March 31, 2003

Union Oil Company of California

T G Dallas
____

Terry G. Dallas

Chief Financial Officer

Signature of witness or notary: ______________________________

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
350 South Grand Avenue
Los Angeles CA 90071-3405
Telephone (213) 356 6000
Facsimile (213) 356 6363

Independent Accountants' Report
On Applying Agreed Upon Procedures

To the Board of Directors of
Union Oil Company of California:

We have performed the procedures enumerated below, which were agreed to by Union Oil Company of California (the "Company") referred to as the "Specified User", solely to assist you in evaluating whether the amounts related to tangible net worth, total assets in the United States and percentage of total assets in the United States included in the letter dated March 31, 2003 of Mr. Terry G. Dallas, Chief Financial Officer ("CFO"), to the United States of America Nuclear Regulatory Commission (the "Commission") were derived from the audited consolidated financial statements and accompanying footnotes of the Company as of and for the year ended December 31, 2002 (the "Financial Statements") or from other financial records of the Company.

This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants of the United States. The sufficiency of these procedures is solely the responsibility of the Specified User of this report. Consequently, we make no representation regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

The attached schedule reconciles the specified information furnished in the CFO's letter in response to the regulations with the Company's consolidated financial statements. In connection therewith, we have performed the following:

1. We agreed the amounts in the column "Per Financial Statements" with amounts contained in the Company's aforementioned audited consolidated financial statements and related notes for the year ended December 31, 2002, or to a schedule prepared by the Company reconciling the amounts to the aforementioned audited consolidated financial statements and notes for the year ended December 31, 2002. No exceptions were noted.

2. We agreed the amounts in the column "Per CFO's Letter" with the letter prepared in response to the Commission's request. No exceptions were noted.

3. We recalculated the totals and percentages within the CFO's letter. No exceptions were noted.

We were not engaged to, and did not, perform an examination, the objective of which would be the expression of an opinion on the financial information included in the letters to the Commission dated March 31, 2003. Accordingly, we do not express such an opinion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

This report is intended solely for the information and use of the Specified User listed above, and is not intended to be and should not be used by anyone other than this specified party.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
March 31, 2003

UNION OIL COMPANY OF CAIIFORNIA
Year Ended December 31, 2002
Dollar amounts in millions

Schedule of Reconciling Amounts Contained in Chief Financial Officer's Letter with Amounts in Financial Statements

Line Number in CFO's Letter		Per Financial Statements	Reconciling Items	Per CFO's Letter
5	Net worth	$ 3,828		
	Less: Cost in excess of value of intangible assets acquired and purchased intangibles	(164)		
		3,664		
	Accrued decommissioning costs included in current liabilities		-	
	Tangible net worth (plus decommissioning costs)			$ 3,664
6	Total Assets	$ 10,771		
	Less: Assets in foreign countries	(5,664)		
		5,107		
	Reconciling Items		-	
	Assets in the United States			$ 5,107

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors of Union Oil Company of California:

We have audited the accompanying consolidated balance sheets of Union Oil Company of California and its subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of earnings, cash flows and shareholder's equity and comprehensive income for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of Union Oil Company of California's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Union Oil Company of California and its subsidiaries as of December 31, 2002 and 2001 and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
February 14, 2003
Los Angeles, California

CONSOLIDATED EARNINGS

UNION OIL COMPANY

Millions of dollars	Years ended December 31, 2002	2001	2000
Revenues			
Sales and operating revenues	$ 5,224	$ 6,708	$ 8,956
Interest, dividends and miscellaneous income	31	59	166
Gain on sales of assets	42	24	85
Total revenues	5,297	6,791	9,207
Costs and other deductions			
Crude oil, natural gas and product purchases	1,701	2,492	5,158
Operating expense	1,338	1,420	1,214
Administrative and general expense	146	118	126
Depreciation, depletion and amortization	973	967	821
Impairments	47	118	66
Dry hole costs	118	175	156
Exploration expense	246	252	260
Interest expense (a)	179	192	210
Property and other operating taxes	60	77	68
Total costs and other deductions	4,808	5,811	8,079
Earnings from equity investments	154	144	134
Earnings from continuing operations before income taxes and minority interests	643	1,124	1,262
Income taxes	283	457	500
Minority interests	6	41	16
Earnings from continuing operations	354	626	746
Discontinued operations			
Refining, marketing and transportation			
Gain on disposal (b)	1	17	-
Agricultural products			
Gain on disposal (c)	-	-	37
Earnings from discontinued operations	1	17	37
Cumulative effect of accounting change	-	(1)	-
Net earnings	$ 355	$ 642	$ 783
(a) Net of capitalized interest of :	$ 46	$ 27	$ 13
(b) Net of tax expense of :	$ 1	$ 10	$ -
(c) Net of tax expense of :	$ -	$ -	$ 18

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

UNION OIL COMPANY

Millions of dollars	At December 31, 2002	2001
Assets		
Current assets		
Cash and cash equivalents	$ 168	$ 190
Accounts and notes receivable - net	997	849
Inventories	97	102
Deferred income taxes	90	123
Other current assets	26	32
Total current assets	1,378	1,296
Investments and long-term receivables - net	1,044	1,405
Properties - net	7,868	7,484
Goodwill	122	30
Deferred income taxes	214	128
Other assets	145	107
Total assets	$ 10,771	$ 10,450
Liabilities and Shareholder's Equity		
Current liabilities		
Accounts payable (a)	$ 1,082	$ 874
Taxes payable	223	249
Interest payable	50	49
Current portion of environmental liabilities	113	124
Current portion of long-term debt and capital leases	6	9
Other current liabilities	161	116
Total current liabilities	1,635	1,421
Long-term debt and capital leases	3,002	2,897
Deferred income taxes	593	627
Accrued abandonment, restoration and environmental liabilities	622	590
Other deferred credits and liabilities	816	724
Subsidiary stock subject to repurchase	-	70
Minority interests	275	449
Commitments and contingencies - Note 21		
Common stock ($2-1/12 par value) 260,000,000 shares authorized. Shares outstanding - 1,000 in 2002 and 2001	-	-
Capital in excess of par value	1,292	891
Unearned portion of restricted stock issued	-	(2)
Retained earnings	3,025	2,878
Accumulated other comprehensive income (loss)	(486)	(88)
Notes receivable - key employees	(3)	(7)
Total shareholder's equity	3,828	3,672
Total liabilities and shareholder's equity	$ 10,771	$ 10,450

(a) Includes amounts due to Parent Company of $57 million in 2002 and $51 million in 2001.

See Notes to the Consolidated Financial Statements.

CONSOLIDATED CASH FLOWS **UNION OIL COMPANY**

Millions of dollars	Years ended December 31, 2002	2001	2000
Cash Flows from Operating Activities			
Net earnings	$ 355	$ 642	$ 783
Adjustments to reconcile net earnings to net cash provided by operating activities			
Depreciation, depletion and amortization	973	967	821
Impairments	47	118	66
Dry hole costs	118	175	156
Amortization of exploratory leasehold costs	98	95	84
Deferred income taxes	18	81	17
Gain on sales of assets (pre-tax)	(42)	(24)	(85)
Gain on disposal of discontinued operations (pre-tax)	(2)	(27)	(23)
Earnings applicable to minority interests	6	41	16
Other	(55)	31	173
Working capital and other changes related to operations			
Accounts and notes receivable	(160)	462	(389)
Inventories	5	(14)	24
Accounts payable	196	(273)	91
Taxes payable	52	(33)	92
Other	(4)	(105)	(153)
Net cash provided by operating activities	1,605	2,136	1,673
Cash Flows from Investing Activities			
Capital expenditures (includes dry hole costs)	(1,670)	(1,727)	(1,302)
Major acquisitions	-	(646)	(318)
Proceeds from sales of assets	163	81	284
Proceeds from sales of discontinued operations	3	25	267
Net cash used in investing activities	(1,504)	(2,267)	(1,069)
Cash Flows from Financing Activities			
Long-term borrowings	585	519	-
Reduction of long-term debt and capital lease obligations	(495)	(225)	(453)
Dividends paid to Parent Company	(208)	(190)	(218)
Loans to key employees	5	-	(7)
Minority interests	(8)	(17)	(25)
Other	(2)	-	1
Net cash provided by (used in) financing activities	(123)	87	(702)
Decrease in cash and cash equivalents	(22)	(44)	(98)
Cash and cash equivalents at beginning of year	190	234	332
Cash and cash equivalents at end of year	$ 168	$ 190	$ 234
Supplemental disclosure of cash flow information:			
Cash paid during the period for:			
Interest (net of amount capitalized)	$ 180	$ 195	$ 221
Income taxes (net of refunds)	$ 249	$ 368	$ 374

See Notes to the Consolidated Financial Statements.

CONSOLIDATED SHAREHOLDER'S EQUITY | UNION OIL COMPANY

Millions of dollars	At December 31, 2002	2001	2000
Common stock			
Shares Authorized - 260,000,000			
Shares Outstanding - 1,000	$ -	$ -	$ -
Capital in excess of par value			
Balance at beginning of year	891	891	891
Issuance of Parent Company common stock for acquisition of Pure Resources' minority interest	391	-	-
Other issuance of Parent Company common stock	10	-	-
Balance at end of year	1,292	891	891
Unearned portion of Parent Company restricted stock and options issued			
Balance at beginning of year	(2)	(3)	-
Issuance of Parent Company restricted stock and options	-	-	(3)
Amortization of Parent Company restricted stock and options	2	1	-
Balance at end of year	-	(2)	(3)
Retained earnings			
Balance at beginning of year	2,878	2,426	1,861
Net earnings for year	355	642	783
Cash dividends declared to Parent Company	(208)	(190)	(218)
Balance at end of year	3,025	2,878	2,426
Notes receivable - Key employees			
Balance at beginning of year	(7)	(7)	-
Accrued interest on loans to key employees	-	-	-
Principal and interest payments received from key employees	4	-	-
Issuance of loans to key employees	-	-	(7)
Balance at end of year	(3)	(7)	(7)
Accumulated other comprehensive income (loss)			
Balance at beginning of year	(88)	(53)	(33)
Foreign currency translation adjustments	(15)	(40)	(20)
Deferred net gains (losses) on hedging instruments	(49)	60	-
Cumulative effect of accounting change	-	(59)	-
Minimum pension liability adjustment	(334)	4	-
Balance at end of year (a)	(486)	(88)	(53)
Total shareholder's equity	$ 3,828	$ 3,672	$ 3,254

(a) At year-end 2002, other comprehensive income was comprised of unrealized currency translation losses of $100 million, deferred net losses on hedging instruments of $48 million and minimum pension liability adjustment of $338 million. Year-end 2001 other comprehensive income consisted of unrealized currency translation losses of $85 million, deferred net gains on hedging instruments of $60 million, minimum pension liability adjustment of $4 million and cumulative effect of accounting change of $59 million Year-end 2000 comprehensive income consisted of unrealized currency translation losses of $45 million and minimum pension liability adjustment of $8 million.

See Notes to the Consolidated Financial Statements.

Millions of dollars	Years ended December 31, 2002	2001	2000
Net earnings	$ 355	$ 642	$ 783
Cumulative effect of change in accounting principle			
SFAS No. 133 adoption (a)	-	(59)	-
Change in unrealized gains (losses) on hedging instruments (b)	(57)	32	-
Reclassification adjustment for settled hedging contracts (c)	8	28	-
Unrealized foreign currency translation adjustments	(15)	(40)	(20)
Minimum pension liability adjustment (d)	(334)	4	-
Total comprehensive income	$ (43)	$ 607	$ 763
(a) Net of tax effect of:	-	36	-
(b) Net of tax effect of:	33	(19)	-
(c) Net of tax effect of.	(4)	(16)	-
(d) Net of tax effect of:	196	(2)	-

See Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation - For the purpose of this report, Union Oil Company of California ("Union Oil") and its consolidated subsidiaries will be referred to as the Company.

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

Use of Estimates - The consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America, which require management to make estimates and assumptions that affect the amounts of assets and liabilities and the disclosures of contingent liabilities as of the financial statement date and the amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition – Revenues associated with sales of crude oil, condensate, natural gas, natural gas liquids and other products are recorded when title passes to the customer. Natural gas sales revenues from properties in which the Company has an interest with other producers are recognized on the basis of Union Oil's working interest ("entitlement" method of accounting). Natural gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total natural gas production. Any amount received in excess of the Company's share is treated as a liability. If the Company takes less than it is entitled, the under-delivery is recorded as a receivable. At December 31, 2002 and 2001, the Company had both receivables and payables related to under and over liftings of natural gas. The Company's worldwide net gas imbalance was a receivable of $29 million and $42 million, for the two years respectively.

Inventories - Inventories are generally valued at the lower of cost or market. The costs of inventories are primarily determined using the last-in, first-out ("LIFO") method or average costs method. Cost elements primarily consist of raw materials and production expenses.

Impairment of Assets - Oil and gas developed and undeveloped properties are regularly assessed for possible impairment, generally on a field-by-field basis where applicable, using the estimated undiscounted future cash flows of each field. Impairment losses are recognized when the estimated undiscounted future cash flows are less than the current net book values of the properties in a field. The measurement of the impairment amount to be recorded is based on expected discounted future cash flows. These expected future cash flows are estimated based on management's plans to continue to produce and develop proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on management's best estimate of future oil and gas prices using market-based information. The estimated future level of production is based on assumptions surrounding future commodity prices, lifting and development costs, field decline rates, market demand and supply, the economic regulatory climates and other factors.

Impairment charges are also made for other long-lived assets, including goodwill, when it is determined that the carrying values of the assets may not be recoverable. A long-lived asset is reviewed for impairment whenever events or changes in circumstances indicate that the carrying value of the asset may not be recoverable, notwithstanding a required annual review of goodwill.

Oil and Gas Exploration and Development Costs - The Company follows the successful efforts method of accounting for its oil and gas activities. Acquisition costs of exploratory acreage are capitalized when incurred. Such costs related to the portion of properties expected to be non-commercial, based on exploratory experience and judgment, are amortized for impairment over the shorter of the exploratory period or the lease/concession holding period. This impairment amortization is reflected as a component of exploration expense on the consolidated earnings statement. Costs of successful leases are transferred to proved properties. Exploratory drilling costs are initially capitalized. If an exploratory well results in discovery of commercial reserves, the well investment is transferred to proved properties at the time reserves are booked. Exploratory wells that are non-commercial are expensed as dry holes. Geological and geophysical costs for exploration and leasehold rentals for unproved properties are expensed. Development costs of proved properties, including unsuccessful development wells, are capitalized.

Depreciation, Depletion and Amortization - Depreciation, depletion and amortization related to acquisition costs and development costs of proved properties are calculated at unit-of-production rates based upon total proved and proved developed reserves, respectively. Estimated future abandonment and removal costs for onshore and offshore producing facilities are calculated at unit-of-production rates based upon estimated proved reserves. Depreciation of other properties is generally on a straight-line method using various rates based on estimated useful lives.

Maintenance and Repairs - Expenditures for maintenance and repairs are expensed. In general, improvements are charged to the respective property accounts.

Retirement and Disposal of Properties - Upon retirement of facilities depreciated on an individual basis, remaining book values are charged to depreciation expense. For facilities depreciated on a group basis, remaining book values are charged to accumulated allowances. Gains or losses on sales of properties are included in current earnings.

Income Taxes - The Company uses the liability method for reporting income taxes, under which current and deferred tax liabilities and assets are recorded in accordance with enacted tax laws and rates. Under this method, the amounts of deferred tax liabilities and assets at the end of each period are determined using the tax rate expected to be in effect when taxes are actually paid or recovered. Future tax benefits are recognized to the extent that realization of such benefits is more likely than not.

Deferred income taxes are provided for the estimated income tax effect of temporary differences between financial and tax bases in assets and liabilities. Deferred tax assets are also provided for certain tax credit carryforwards. A valuation allowance to reduce deferred tax assets is established when deemed appropriate.

Foreign Currency Translation - Foreign exchange translation adjustments as a result of translating a foreign entity's financial statements from its functional currency into U.S. dollars are included as a separate component of other comprehensive income in shareholder's equity. The functional currency for all operations, except Canada and equity investments in Thailand and Brazil, is the U.S. dollar. Gains or losses incurred on currency transactions in other than a country's functional currency are included in net earnings.

Environmental Expenditures - Expenditures that relate to existing conditions caused by past operations are expensed. Environmental expenditures that create future benefits or contribute to future revenue generation are capitalized.

Liabilities related to environmental assessments and future remediation costs are recorded when such liabilities are probable and the amounts can be reasonably estimated. The Company considers a site to present a probable liability when an investigation has identified environmental remediation requirements for which the Company is responsible. The timing of accruing for remediation costs generally coincides with the Company's completion of investigation or feasibility work and its recommendation of a remedy or commitment to an appropriate plan of action. Environmental liabilities are not discounted or reduced by possible recoveries from third parties. However, accrued liabilities for Superfund and similar sites reflect anticipated allocations of liabilities among settling participants. Environmental remediation expenditures required for properties held for sale are capitalized up to the realizable market value.

Risk Management - The objectives of the Company's risk management strategies include reducing the overall volatility of the Company's cash flows, preserving revenues and pursuing outright pricing positions in hydrocarbon derivative financial instruments (hydrocarbon derivatives). As part of its overall risk management strategy, the Company enters into various derivative instrument contracts to offset portions of its exposures to changes in interest rates, changes in foreign currency exchange rates, and fluctuations in crude oil and natural gas prices. In general, the Company enters into derivative instruments to hedge two types of exposures: cash flow exposures and fair value exposures. Hedges of cash flow exposures are generally undertaken to reduce cash flow volatility associated with forecasted transactions. They may also be used to reduce volatility associated with cash flows to be paid related to recognized liabilities. Hedges of fair value exposures are undertaken to hedge recognized assets or liabilities or unrecognized firm commitments against changes in value.

Interest Rates – From time to time, the Company enters into interest rate swap contracts to manage the interest cost of its debt with the objective of minimizing the volatility and magnitude of the Company's borrowing costs.

Foreign Currency – Various foreign currency forward, option and swap contracts are entered into by the Company to manage its exposures to adverse impacts of foreign currency fluctuations on recognized obligations and anticipated transactions.

Commodities – The Company uses hydrocarbon derivatives such as futures, swaps, collars and options to mitigate the Company's overall exposure to fluctuations in hydrocarbon commodity prices. The Company also pursues outright pricing positions using derivatives.

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities", all derivative instruments are recorded as assets or liabilities on the balance sheet at their fair values. The Company routinely enters into various purchase and sale contracts that will ultimately result in the physical delivery of hydrocarbon commodities. The Company has determined that the normal purchase and normal sale exception included in paragraph 10(b) of SFAS No. 133 applies to such contracts. Accordingly, such contracts are not accounted for as derivatives pursuant to SFAS No.133.

At the inception of a derivative contract, the Company may choose to designate and document a derivative as a cash flow hedge or a fair value hedge. Changes in the values of derivatives not designated and documented as hedges are recorded in current-period earnings.

Changes in the values of derivatives that qualify for, and are designated and effective as, cash flow hedges are deferred and recorded as components of accumulated other comprehensive income until the hedged transactions occur and are then recognized in earnings. Any ineffectiveness that is related to changes in the values of cash flow hedge derivatives is recognized immediately in earnings as a component of sales revenues. During 2001, the Company changed its methodology for calculating the effectiveness of options used in cash flow hedges to conform with the April 2001 interpretation of SFAS No. 133 by the Financial Accounting Standards Board's ("FASB") "Derivatives Implementation Group". Unrealized gains and losses associated with the time value of cash flow hedging options that are expected to be held to maturity are included in the effectiveness calculations and, generally, deferred as components of other comprehensive income until the hedged transactions are recognized in earnings. Previously, these unrealized gains and losses had been excluded from the measurement of hedge effectiveness and recognized in sales revenues as they occurred. Changes in the values of derivatives that qualify for, and are designated and effective as, fair value hedges are recognized in current-period earnings as components of the line items reflecting the underlying hedged transactions. Changes in the fair values of the underlying hedged items (e.g., recognized assets, liabilities or unrecognized firm commitments) are also recognized in current-period earnings and offset the changes in the values of the corresponding hedging derivatives. Any resulting fair value hedge ineffectiveness is recognized in current-period earnings as the difference between the offsetting changes in values of the derivative and the underlying hedged items.

The Company documents its risk management objectives, its strategies for undertaking various hedge transactions and the relationships between hedging instruments and hedged items. Derivatives designated as cash flow hedges are linked to forecasted transactions. Derivatives identified as fair value hedges are linked to specific assets, liabilities or firm commitments. At hedge inceptions and on an on-going basis, the Company assesses whether changes in the values of derivatives used in hedging activities are highly effective in offsetting changes in the values of the hedged items. The Company discontinues hedge accounting prospectively when either (1) it determines that a derivative is not highly effective as a hedge, (2) the derivative is sold, exercised or otherwise terminated, (3) management elects to remove the derivative's hedge designation, (4) the hedged transaction is no longer expected to occur, or (5) a hedged item no longer meets the definition of a firm commitment. When a hedged forecasted transaction is no longer expected to occur, the derivative continues to be carried on the balance sheet at its fair value and all unrealized gains and losses that were previously deferred in accumulated other comprehensive income are recognized immediately in earnings. When a hedged item no longer meets the definition of a firm commitment, the derivative continues to be carried on the balance sheet at its fair value and any asset or liability that was recorded on the balance sheet for the change in value of the hedged firm commitment is removed from the balance sheet and recognized immediately in current-period earnings. In all other situations where hedge accounting is discontinued, the derivatives continue to be carried on the balance sheet at their fair values and any prospective changes in their fair values are recognized in current-period earnings. Deferred gains and losses already recorded in accumulated other comprehensive income remain until the forecasted transactions occur, at which time those gains and losses are recognized in earnings.

Capitalized Interest - Interest is capitalized on certain construction and development projects as part of the costs of the assets.

Other - The Company considers cash equivalents to be all highly liquid investments purchased with a maturity of three months or less.

Expenses incurred for transporting crude oil and natural gas are included as a component of operating expense.

Certain items in prior year financial statements have been reclassified to conform to the 2002 presentation.

NOTE 2 – ACCOUNTING CHANGES

SFAS No. 142: Effective January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 142 addresses accounting for goodwill and identifiable intangible assets subsequent to their initial recognition, eliminates the amortization of goodwill and provides specific steps for testing the impairment of goodwill. Separable intangible assets that are not deemed to have an indefinite life will continue to be amortized over their useful lives. SFAS No. 142 also eliminates amortization of the excess of cost over the underlying equity in the net assets of an equity method investee that is recognized as goodwill. The adoption of the statement did not have a material effect on the Company's financial position or results of operations.

SFAS No. 143: In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This statement requires that the Company recognize liabilities related to the legal obligations associated with the retirement of its tangible long-lived assets at fair values in the periods in which the obligations are incurred (typically when the assets are installed). These obligations include the required decommissioning and removal of certain oil and gas platforms, plugging and abandonment of oil and gas wells and facilities and the closure and site restoration of certain mining facilities.

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

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

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

The Company expects to recognize a one time after-tax charge in the range of $70 million to $85 million as the cumulative effect of an accounting change related to the adoption of SFAS No. 143.

SFAS No. 144: Effective January 1, 2002, the Company also adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of", and the accounting and reporting provisions of APB No. 30, "Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and

Transactions". The adoption of SFAS No. 144 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 145: The Company adopted SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections", effective January 1, 2002. This statement rescinds SFAS No. 4, "Reporting Gains and Losses from Extinguishment of Debt", and an amendment of that statement, SFAS No. 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements". This statement also rescinds or amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The adoption of SFAS No. 145 did not have a material effect on the Company's financial position or results of operations.

SFAS No. 146: In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". This statement provides guidance on the recognition and measurement of liabilities associated with disposal activities and is effective for the Company on January 1, 2003. The Company does not expect the adoption of SFAS No. 146 to have a significant impact on its financial position or results of operations.

FASB Interpretation No. 45: In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." This Interpretation requires the recognition of certain guarantees as liabilities at fair market value and is effective for guarantees issued or modified after December 31, 2002. The Company has included the disclosure requirements of the Interpretation in note 21 and does not expect the adoption of this Interpretation to have a significant impact on its financial position or results of operations.

FASB Interpretation No. 46: In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities." This Interpretation requires the consolidation of certain companies that are defined as variable interest entities. This Interpretation is effective for new variable interest entities as of February 1, 2003. The effective date for entities existing prior to February 1, 2003 is July 1, 2003. The Company has included the disclosure requirements of the Interpretation in this report and expects the adoption of the recognition (i.e., consolidation) requirements of the Interpretation to increase its consolidated long-term debt by approximately $320 million. This amount that the Company anticipates to consolidate when it adopts the Interpretation includes $242 million related to a partnership interest in which it has a minority interest liability (see note 20 for further details) and $78 million of third-party debt related to Dayabumi Salak Pratma, Ltd. ("DSPL"), an equity investee that sells electricity generated from geothermal steam in Indonesia (see note 13 for further details).

NOTE 3 – ACQUISITIONS

On October 29, 2002, the Company completed its exchange offer for the remaining shares of Pure Resources, Inc. ("Pure") that it did not already own. Pursuant to the offer, the Company exchanged 0.74 shares of common stock of Unocal Corporation, Union Oil's parent company ("Parent Company"), for each share of Pure common stock tendered. The Company accepted tenders of 16,634,625 Pure shares in the exchange offer which, when combined with the 65 percent of the shares it already owned, represented approximately 97.5 percent of Pure's outstanding common shares. On October 30, 2002, the Company completed a short-form merger to acquire the remaining 2.5 percent of Pure's outstanding shares at the same 0.74 exchange ratio used in the exchange offer. Consequently, Pure became a wholly owned subsidiary of the Company. This transaction was valued at approximately $410 million and was accounted for as a purchase. As a result of the transaction, properties have increased by $121 million, goodwill of $80 million was recorded representing the excess of cost over fair value of the asset and liabilities acquired, deferred tax liabilities increased by $53 million, long-term debt increased by $10 million, reflecting the fair value of Pure's debt, and shareholder's equity increased by $391 million for the value of the common stock. This acquisition provides the Company with a number of operational efficiency opportunities including: combining certain Pure operations with similar Union Oil operations to reduce costs; technology efficiencies; the elimination of redundant overhead and administrative costs including public company costs. Recognition of the value of these opportunities contributed to a purchase price that exceeded the fair value assigned to the assets and liabilities acquired and resulted in an allocation of cost to goodwill. A minority interest liability of $151 million relating to the Pure shares and a $112 million obligation for "Subsidiary stock subject to repurchase" were eliminated from the Company's consolidated balance sheet. See notes 20, 21 and 23 for further details.

NOTE 4 - DISPOSITIONS OF ASSETS

In 2002, cash proceeds received from asset sales and discontinued operations totaled $166 million, with pre-tax gains of $44 million. The proceeds included $65 million from the sale of certain investment interests in nonstrategic pipelines in the U.S, with a pre-tax gain of $49 million. Cash proceeds of approximately $44 million were from the sale of real estate and other miscellaneous properties, with a pre-tax gain of $20 million, and $32 million were from the sale, by the Company's Pure subsidiary, of oil and gas producing properties in the U.S, with a pre-tax gain of $4 million. Sale proceeds also included $22 million from various other oil and gas asset sales, with a pre-tax loss of $31 million, and cash proceeds of $3 million related to a participation payment received from the purchaser of the Company's former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline, which included $2 million pre-tax that was earned in 2001.

In 2001, cash proceeds received from asset sales and discontinued operations totaled $106 million, with pre-tax gains of $51 million. The proceeds included $25 million of payments received from the purchaser of the Company's former West Coast refining, marketing and transportation assets. The 2001 payment of $25 million, along with another $2 million earned in 2001 but yet to be collected, was recorded as a pre-tax gain of $27 million. The Company also received $63 million from the sale of certain oil and gas properties, primarily located in the U.S. Gulf of Mexico, with a pre-tax gain of $21 million. In addition, the Company received $18 million from the sale of real estate and other assets, with a pre-tax gain of $3 million.

In 2000, cash proceeds received from asset sales and discontinued operations totaled $551 million, with pre-tax gains of $108 million. The proceeds included $242 million received from the sale of the agricultural products business, with a pre-tax gain of $23 million. The proceeds also included $80 million from the sale of the Company's graphite business, with a pre-tax gain of $12 million and $71 million from the sale of securities received as part of the consideration in the sale of the agricultural business, with a pre-tax loss of $6 million. The Company also received cash proceeds of $98 million from the sale of certain oil and gas properties, with a pre-tax gain of $3 million and $35 million in real estate and other assets, with a pre-tax gain of $10 million. Cash proceeds also included $25 million received from the purchaser of the Company's former West Coast refining, marketing and transportation assets.

NOTE 5 - LEASE RENTAL OBLIGATIONS

The Company has operating leases for drilling rigs, office space and other property and equipment having initial or remaining noncancelable lease terms in excess of one year.

Future minimum rental payments for operating leases at December 31, 2002 were as follows:

Millions of dollars	
2003	169
2004	140
2005	96
2006	25
2007	18
Thereafter	25
Total minimum lease rental payments	$ 473

The Company has a five-year lease agreement relating to its *Discoverer Spirit* deepwater drillship, with a remaining term of approximately two years and nine months at December 31, 2002. In 2001, the Company signed a sublease agreement with a third-party for a period that began in December 2001 and ended in mid-September 2002. Under the provisions of that agreement, the third party assumed all of the lease payments to the lessor during the sublease period. The drillship has a current minimum daily rate of approximately $224,000. At December 31, 2002, the future remaining minimum lease-rental payment obligation was $222 million as included in the table above.

Net operating lease rental expense for continuing operations was as follows:

	Years ended December 31,		
Millions of dollars	2002	2001	2000
Fixed rentals	$ 72	$ 58	$ 58
Contingent rentals (based primarily on sales and usage)	-	-	1
Sublease rental income	(4)	(3)	(4)
Net rental expense	$ 68	$ 55	$ 55

NOTE 6 - IMPAIRMENT OF ASSETS

The Company, as part of its regular assessment, reviewed its developed and undeveloped oil and gas properties and other long-lived assets for possible impairment. In 2002, the Company recorded pre-tax charges of $41 million ($26 million after-tax) for the impairment of oil and gas fields in Alaska and the Gulf of Mexico region primarily due to lower reserve estimates, production forecasts and future expenses. The impairment in Alaska was $24 million pre-tax while the impairment for the Gulf of Mexico region was $17 million. The Company also recorded a pre-tax charge of $4 million ($2 million after-tax), for the impairment of its investment in a U.S. pipeline company, carried in its Midstream segment, in which the Company owns an equity interest and that was being held for sale. Lastly, the Company recorded a pre-tax charge of $2 million to impair its investment in an electronic commerce provider.

In 2001, the Company recorded pre-tax charges of $118 million ($74 million after-tax) for the impairment of certain oil and gas properties, primarily located in the Gulf of Mexico shelf, due principally to lower commodity prices. Earnings from equity investments included pre-tax charges of $19 million ($12 million after-tax), reflecting the Company's portion of the impairment of certain oil and gas Gulf of Mexico shelf properties held by one of its equity investees. In 2000, the Company recorded pre-tax charges of $13 million for the impairment of certain U.S. Lower 48 oil and gas properties. The Company's Molycorp, Inc. ("Molycorp"), subsidiary recorded a pre-tax charge of $53 million for the impairment of the Questa, New Mexico, molybdenum mining operation.

NOTE 7 - RESTRUCTURING COSTS

In June 2002, the Company adopted a restructuring plan that resulted in the accrual of a $19 million pre-tax restructuring charge. The charge included the estimated costs of terminating 202 employees in the Company's Sugar Land, Texas, office and field locations. The restructuring plan involved organizational changes to eliminate unnecessary work processes in the Company's Gulf Region business unit, which is part of the U.S. Lower 48 operations in the Exploration and Production segment.

The restructuring charge was reflected in the operating expense line on the consolidated earnings statement and included approximately $14 million for termination costs to be paid to the employees over time, about $3 million for outplacement and other costs and about $2 million for benefit plan curtailment costs. All of the affected employees had been terminated as of December 31, 2002. Approximately $12 million of the restructuring costs had been paid and charged against the liability in 2002, leaving accrued costs of $7 million on the consolidated balance sheet at December 31, 2002. The remaining costs are expected to be paid in 2003.

In November 2002, the Company adopted a restructuring plan that resulted in the accrual of a $4 million pre-tax restructuring charge related to Exploration and Production operations in Alaska. The restructuring charge was included in the operating expense line on the consolidated earnings statement and reflected the costs of terminating 46 employees in order to streamline operations, technical and support functions. Fourteen of the affected employees had been terminated as of December 31, 2002, while the other affected employees have been given notice of termination dates in the first quarter of 2003. Approximately $1 million of the restructuring costs had been paid and charged against the liability in 2002, leaving accrued costs of $3 million on the consolidated balance sheet at December 31, 2002. The remaining costs are expected to be paid during 2003 and the first half of 2004.

NOTE 8 - INCOME TAXES

The components of the income tax provision for continuing operations were as follows:

	Years ended December 31,		
Millions of dollars	2002	2001	2000
Earnings (loss) from continuing operations before income taxes and minority interests (a)			
United States	$ (154)	$ 441	$ 644
Foreign	797	683	618
Earnings from continuing operations before income taxes and minority interests	$ 643	$ 1,124	$ 1,262
Income taxes			
Current			
Federal	$ (47)	$ 8	$ 43
State	7	12	20
Foreign	221	351	374
Total current taxes	181	371	437
Deferred			
Federal	(64)	68	155
State	-	(1)	(2)
Foreign	159	14	(93)
Total deferred taxes	95	81	60
Sub-total income taxes	276	452	497
Union Oil Company of California allocation (b)	7	5	3
Total income taxes	$ 283	$ 457	$ 500

(a) Amounts attributable to the Corporate and Other segment are allocated.

(b) The Company files a consolidated tax return with the Parent. This allocation presents estimated tax information for Union Oil Company of California for report purposes only.

For 2002 the Company will elect to carryback its current year domestic source net operating loss, which will result in a refund of prior year federal income tax paid. In addition, 2002 reflects a decrease in current foreign tax provision of $78 million and an increase in deferred foreign tax provision of $89 million due to the settlement of past issues as a result of renegotiating the geothermal sales contract in Indonesia. The Indonesia geothermal adjustments relate to prior year tax provisions and have no cash flow impact.

The following table is a reconciliation of income taxes at the federal statutory income tax rates to income taxes as reported in the consolidated earnings statement.

Millions of dollars	Years ended December 31, 2002	2001	2000
Federal statutory rate	35%	35%	35%
Taxes on earnings from continuing operations before minority interests at statutory rate	$ 212	$ 382	$ 433
Taxes on foreign earnings in excess of statutory rate	73	73	23
Provision for prior year income tax issues	-	-	28
Dividend exclusion	(15)	(17)	(16)
Other	6	14	29
Union Oil Company of California allocation	7	5	3
Total	$ 283	$ 457	$ 500

The significant components of deferred income tax assets and liabilities included in the consolidated balance sheet at December 31, 2002 and 2001 were as follows:

Millions of dollars	At December 31, 2002	2001
Deferred tax assets:		
Exploratory costs	$ 289	$ 321
Federal AMT and other tax credits	209	136
Future abandonment costs	139	142
Litigation and environmental costs	107	106
Doubtful receivables	14	96
Postretirement benefit costs	82	87
Pension plans	28	-
Forward sales of natural gas	27	31
Price risk and interest rate management activities	41	18
Other deferred tax assets	176	139
Total deferred tax assets	1,112	1,076
Deferred tax liabilities:		
Depreciation, depletion and intangible drilling costs	(1,153)	(1,018)
Pension plans	-	(181)
Investment in subsidiaries and affiliates	(79)	(125)
Other deferred tax liabilities	(169)	(128)
Total deferred tax liabilities	(1,401)	(1,452)
Total net deferred tax liabilities	$ (289)	$ (376)

The net deferred tax liabilities at December 31, 2002 reflect the recognition of a minimum pension liability for the Company's Qualified Retirement Plan in 2002 and the resulting charge to the other comprehensive income component of shareholder's equity which was recorded net of $196 million in deferred income taxes. See note 16 for additional information. No deferred U.S. income tax liability has been recognized on the undistributed earnings of foreign subsidiaries that have been retained for reinvestment. If distributed, no additional U.S. tax is expected due to the availability of foreign tax credits. The undistributed earnings for tax purposes, excluding previously taxed earnings, were estimated at $1.9 billion as of December 31, 2002.

The Company estimates that approximately $154 million of unused foreign tax credits will be available after the filing of the 2002 consolidated tax return, with various expiration dates through the year 2007. No deferred tax asset for these foreign tax credits has been recognized for financial statement purposes. The federal alternative minimum tax credits are available to reduce future U.S. federal income taxes on an indefinite basis. At December 31, 2002, the Company's Pure subsidiary had net operating loss carryforwards of approximately $21 million, which are available to offset future taxable income subject to annual limitations. The loss carryforwards begin to expire in 2010, and the tax effect of those carryforwards are included in other deferred tax assets.

NOTE 9 - DISCONTINUED OPERATIONS

	Years ended December 31,		
Millions of dollars	2002	2001	2000
Gain on disposal before income taxes (a)	2	27	55
Income taxes	1	10	18
Total earnings from discontinued operations	1	17	37

(a) Gain on disposal in 2002 and 2001 is related to the refining, marketing and transportation business.
Gain on disposal in 2000 is exclusively related to the agricultural products business.

In 2002, discontinued operations included a $2 million pre-tax gain ($1 million after-tax) related to a participation payment received from the purchaser of the Company's former West Coast refining, marketing and transportation assets covering price differences between California Air Resources Board Phase 2 gasoline and conventional gasoline. In 2001, the Company recorded pre-tax gains of $27 million ($17 million after-tax) related to this sales agreement. The maximum potential payments under this agreement are capped at $100 million and will expire at the end of 2003. To date, the Company has recorded $29 million pre-tax.

In 2000, the Company completed the sale of its agricultural products business for approximately $323 million. The Company reclassified the business unit as a discontinued operation at the end of 1999. The Company recorded a pre-tax gain of $55 million ($37 million after-tax) on the disposal of the business. The gain included $32 million pre-tax ($23 million after-tax) from the results of operations up to the sale date.

NOTE 10 – CASH AND CASH EQUIVALENTS

	At December 31,	
Millions of dollars	2002	2001
Cash	$ 58	$ 12
Time deposits	110	123
Restricted cash	-	5
Marketable securities	-	50
Cash and cash equivalents	$ 168	$ 190

At December 31, 2002, no cash was restricted as to usage or withdrawal, while $5 million was restricted at December 31, 2001. Under the terms of the Company's limited recourse project financing for its share of the Azerbaijan International Operating Company Early Oil Project, the principal and interest payments are payable only out of the proceeds from the Company's sale of crude oil from the project. The next semi-annual debt payment of approximately $3 million will be replenished in the restricted cash account upon the receipt of the next crude oil proceeds.

NOTE 11 – SALES OF ACCOUNTS RECEIVABLE

During 1999, the Company, through a bankruptcy remote wholly-owned subsidiary, Unocal Receivables Corporation ("URC"), entered into a sales agreement with an outside unrelated party that provided for the sale of up to $204 million of an undivided interest in domestic crude oil and natural gas trade receivables. Under the terms of the agreement, the receivables are sold at a discount on a revolving basis and without recourse. The costs incurred under the agreement for the years ended December 31, 2002 and 2001, were $2 million and $1 million, respectively, which was charged to operating expense in the consolidated earnings statement. Amounts sold were reflected as a reduction of accounts and notes receivable in the consolidated balance sheet and in net cash provided by operating activities in the consolidated cash flows statement. During 2002, the sale agreement was modified to reduce the maximum sales of receivables from $204 million to $125 million. At December 31, 2002, the Company had sold $108 million of its domestic trade receivables under this agreement. At December 31, 2001, the Company had sold $70 million of such receivables under this agreement.

The Company's consolidated balance sheet included a note receivable from URC of approximately $66 million and $54 million at December 31, 2002 and 2001, respectively, representing the unsold balance of trade receivables transferred to URC.

NOTE 12 - INVENTORIES

	At December 31,	
Millions of dollars	2002	2001
Crude oil and other petroleum products	$ 43	$ 46
Carbon and mineral products	34	37
Materials, supplies and other	20	19
Total inventories	$ 97	$ 102

Inventories are generally valued at the lower of cost or market. Inventories using the LIFO cost method amounted to $16 million and $20 million as of December 31, 2002 and 2001, respectively. The remaining inventory balances primarily use average cost. The current replacement cost of inventories exceeding the LIFO inventory values was not material at December 31, 2002 and 2001.

NOTE 13 - EQUITY INVESTMENTS

Investments in companies accounted for by the equity method were $686 million, $625 million and $618 million at December 31, 2002, 2001 and 2000, respectively. These investments are reported in investments and long-term receivables on the consolidated balance sheet.

Dividends or cash distributions received from the Company's equity investees were $160 million, $213 million and $77 million for the years 2002, 2001 and 2000, respectively. At December 31, 2002, 2001 and 2000, the excess of the Company's investments in Colonial Pipeline Company and various other pipeline companies was approximately $143 million, $153 million and $159 million, respectively. These equity investees have approximately $1.5 billion of their own debt obligations that are either fully non-recourse or of limited recourse to the Company. Of the total $1.5 billion in equity investee debt, $1.2 billion is that of Colonial Pipeline Company, in which the Company holds a 23.44 percent equity interest. The Company guarantees only $25 million of the $1.5 billion total . At December 31, 2002, 2001 and 2000, the Company's shares of the net capitalized costs of other companies engaged in oil and gas exploration and production activities were $347 million, $309 million and $300 million, respectively.

Summarized financial information for these investments and the Company's equity shares are shown below.

	Years ended December 31,					
	2002		2001		2000	
Millions of dollars	Total	Union Oil's Share	Total	Union Oil's Share	Total	Union Oil's Share
Revenues	$ 1,965	$ 548	$ 2,429	$ 515	$ 2,067	$ 705
Costs and other deductions	1,419	394	1,684	371	1,609	571
Net earnings	$ 546	$ 154	$ 745	$ 144	$ 458	$ 134

	At December 31,					
	2002		2001		2000	
Millions of dollars	Total	Union Oil's Share	Total	Union Oil's Share	Total	Union Oil's Share
Current assets	$ 756	$ 248	$ 873	$ 324	$ 706	$ 239
Noncurrent assets	4,653	1,088	4,069	1,084	3,383	916
Current liabilities	787	257	1,429	453	898	304
Noncurrent liabilities	1,975	521	1,753	475	1,718	484
Net equity	2,647	558	1,760	480	1,473	367

DSPL is a special purpose company formed for the purpose of building and operating a geothermal energy fueled power generating facility in Indonesia. Under a long-term electricity sales contract, this entity provides power to the Indonesian state-owned electricity company, PT. PLN (Persero) ("PLN"). Unocal Geothermal of Indonesia, Ltd. ("UGI") owns a 50 percent interest in DSPL and is under contract to administer DSPL operations. DSPL has no employees of its own. DSPL had loans and notes payable totaling $88 million at December 31, 2002. DSPL's debt obligations are non-recourse to UGI and to the Company, as neither entity has guaranteed these obligations. Effective in the third quarter of 2003, a new accounting rule, FASB Interpretation No. 46 (see note 2 for further details), will require the Company to consolidate DSPL resulting in the reporting of the $78 million as long-term debt on the consolidated balance sheet at that time. At December 31, 2002, the Company's maximum exposure to loss as a result of its involvement with DSPL was approximately $100 million.

NOTE 14 – PROPERTIES AND CAPITAL LEASES

Investments in owned and capitalized-leased properties are shown below. Accumulated depreciation, depletion, and amortization for continuing operations were $12,277 million and $11,648 million at December 31, 2002 and 2001, respectively.

	At December 31,			
	2002		2001	
Millions of dollars	**Gross**	**Net**	**Gross**	**Net**
Owned Properties (at cost)				
Exploration and Production				
Exploration				
North America				
Lower 48	$ 516	$ 370	$ 543	$ 420
Alaska	5	5	8	7
Canada	206	137	168	118
International				
Far East	275	250	234	205
Other	147	82	144	99
Production				
North America				
Lower 48	7,548	2,656	7,317	2,638
Alaska	1,410	254	1,356	275
Canada	1,183	837	1,066	811
International				
Far East	5,811	2,002	5,302	1,724
Other	1,185	521	1,045	419
Total exploration and production	18,286	7,114	17,183	6,716
Trade	7	2	8	3
Midstream	496	221	480	216
Geothermal & Power Operations	658	279	644	284
Corporate & Other	693	247	811	259
Total owned properties	20,140	7,863	19,126	7,478
Capitalized-leased properties	5	5	6	6
Total properties and capital leases	$ 20,145	$ 7,868	$ 19,132	$ 7,484

NOTE 15 - POSTEMPLOYMENT BENEFIT PLANS

The Company has numerous plans worldwide that provide eligible employees with retirement benefits. The Company also has medical plans that provide health care benefits for eligible employees and many of its retired employees. The following table sets forth the postretirement benefit obligations recognized in the consolidated balance sheet at December 31, 2002 and 2001. Prepaid pension costs are reported as a component of investments and long-term receivables on the consolidated balance sheet. Postemployment benefit liabilities, including pensions, postretirement medical benefits and other postemployment benefits, are reported as a component of other deferred credits and liabilities on the consolidated balance sheet.

	Pension Benefits		Other Benefits	
Millions of dollars	2002	2001	2002	2001
Change in benefit obligation:				
Projected benefit obligation at January 1,	$ 1,065	$ 925	$ 306	$ 252
Service cost	24	20	3	2
Interest cost	77	75	22	19
Employee contributions	-	-	5	5
Disbursements	(115)	(114)	(29)	(24)
Actuarial losses	143	124	69	52
Plan amendments	13	36	-	-
Curtailments and settlements	(11)	-	(4)	-
Divestitures	1	-	-	-
Effect of foreign exchange rates	-	(1)	-	-
Projected benefit obligation at December 31,	$ 1,197	$ 1,065	$ 372	$ 306
Change in plan assets:				
Fair value of plan assets at January 1,	$ 1,026	$ 1,201	$ -	$ -
Actual return on plan assets	(40)	(64)	-	-
Employer contributions	1	(17)	-	-
Employee contributions	-	-	-	-
Disbursements	(100)	(86)	-	-
Administrative expenses	(5)	(6)	-	-
Settlements	-	-	-	-
Divestitures	-	-	-	-
Effect of foreign exchange rates	-	(2)	-	-
Fair value of plan assets at December 31,	$ 882	$ 1,026	$ -	$ -
Net amount recognized:				
Funded status	$ (315)	$ (39)	$ (372)	$ (306)
Unrecognized net obligation at transition	1	2	-	-
Unrecognized prior service cost	48	44	4	5
Unrecognized net actuarial losses (gains)	676	423	145	85
Net amount recognized	$ 410	$ 430	$ (223)	$ (216)
Components of the above amounts consist of:				
Prepaid pension cost	$ 9	$ 491	$ -	$ -
Accrued benefit liability	(193)	(82)	(223)	(216)
Intangible asset	45	10	-	-
Accumulated other comprehensive loss	549	11	-	-
Net amount recognized	$ 410	$ 430	$ (223)	$ (216)

Most of the Company's plans covering employees outside of North America are unfunded and resulting liabilities are extinguished on a "pay as you go" basis. In 2002 the Company recognized a minimum pension liability of $103 million reflecting the excess of the accumulated benefit obligation over the fair value of plan assets at December 31, 2002 for its Qualified Retirement Plan covering current and former U.S. payroll employees. The recognition of this liability resulted in an after-tax charge of $334 million to the other comprehensive income component of shareholder's equity. The Company was not required to make any cash contributions to the Qualified Retirement Plan during 2002. Pension plan funds are invested in a variety of assets including U.S. and foreign equity securities, debt and fixed income securities, cash and cash equivalents. None of the plans hold Parent Company stock.

The assumed rates to measure the benefit obligation and the expected earnings on plan assets were:

	Pension Benefits			Other Benefits		
Weighted-average assumptions as of December 31,	2002	2001	2000	2002	2001	2000
Discount rates	6.74%	7.24%	7.73%	6.75%	7.25%	7.74%
Rates of salary increases	4.93%	4.50%	4.45%	4.99%	4.50%	4.50%
Expected returns on plan assets	8.40%	9.33%	9.28%	N/A	N/A	N/A

The health care cost trend rate used in measuring the 2002 benefit obligation for the U.S. plan was 9 percent, decreasing ratably to 5 percent in 2006. A one percentage-point change in the assumed health care cost trend rate would have had the following effects on 2002 service and interest cost and the accumulated postretirement benefit obligation at December 31, 2002:

Millions of dollars	One percent Increase	One percent Decrease
Effect on total of service and interest cost components of net periodic expense	$ 3	$ (2)
Effect on postretirement benefit obligation	$ 40	$ (34)

Net periodic pension and postretirement benefits cost are comprised of the following components:

	Pension Benefits			Other Benefits		
Millions of dollars	2002	2001	2000	2002	2001	2000
Service cost (net of employee contributions)	$ 24	$ 20	$ 24	$ 3	$ 2	$ 3
Interest cost	77	75	73	21	19	17
Expected return on plan assets	(105)	(111)	(110)	-	-	-
Amortization of:						
Transition obligation	-	-	-	-	-	-
Prior service cost	6	6	4	1	1	1
Net actuarial (gains) losses	33	2	3	5	1	-
Curtailment and settlement (gains) losses	5	7	(13)	-	-	(6)
Cost of special separation benefits	-	-	-	-	-	-
Net periodic pension and other benefit cost (credit)	$ 40	$ (1)	$ (19)	$ 30	$ 23	$ 15

The Company amortizes the cost of plan amendments and unrecognized actuarial gains and losses on a straight-line basis over the average remaining service period of active plan participants expected to receive benefits.

The projected benefit obligations, accumulated benefit obligations and fair values of plan assets for pension plans with accumulated benefit obligations in excess of plan assets at December 31, 2002 were approximately $1,152 million, $1,019 million and $833 million, respectively. At December 31, 2001 pension plans with accumulated benefit obligations in excess of plan assets consisted solely of unfunded plans with projected benefit obligations of $104 million and accumulated benefit obligations of $74 million.

In 2002 and 2000, the Company recorded costs for employees displaced as a result of asset sales and the Company's restructuring programs. In 2000, the Company completed the transfer of pension assets and liabilities from a retirement plan of a subsidiary to the Company's retirement plan.

The Company has a 401(k) defined contribution savings plan designed to supplement retirement income for U.S. employees. The Company's contributions to the plan were $12 million, $11 million and $13 million in 2002, 2001, and 2000 respectively, which were used by the plan trustee to purchase shares of the Parent Company's common stock in the open market. The Company has the option to direct the trustee to purchase the Parent Company's common stock either in the open market or from it directly. Once the Company's contributions have been used to purchase the Parent Company's common stock, employees have the ability to convert the shares to other investment options, including a variety of mutual funds or a money market fund.

The Company also provides benefits such as workers' compensation and disabled employees' medical care to former or inactive employees after employment but before retirement. The accumulated postemployment benefit obligation was $15 million and $13 million at December 31, 2002 and 2001, respectively.

NOTE 16 - LONG-TERM DEBT AND CREDIT AGREEMENTS

The following table summarizes the Company's long-term debt:

Millions of dollars	At December 31, 2002	At December 31, 2001
Bonds and debentures		
9-1/4% Debentures due 2003	$ 89	$ 89
9-1/8% Debentures due 2006	200	200
6-1/5% Industrial Development Revenue Bonds due 2008	20	21
7% Debentures due 2028	200	200
7-1/2% Debentures due 2029	350	350
Notes		
Medium-term notes due 2003 to 2015 (7.84%) (a)	330	502
6-3/8% Notes due 2004	200	200
7-1/5% Notes due 2005	200	200
6-1/2% Notes due 2008	100	100
7.35% Notes due 2009	350	350
5.05% Notes due 2012	400	-
Other		
Canadian Bank Credit Ageement	186	-
Northrock consolidated debt and capital leases	6	81
Pure consolidated debt	359	587
Azerbaijan Limited Recourse Loan	28	36
Other miscellaneous debt	1	1
Bond (discount) premium	(11)	(11)
Total debt and capital leases	3,008	2,906
Less current portion of long-term debt and capital leases	6	9
Total long-term debt and capital leases	$ 3,002	$ 2,897

(a) Weighted average interest rate at December 31, 2002.

At December 31, 2002, the amounts of debt and capital leases maturing in 2003, 2004, 2005, 2006, and 2007 were $106 million, $237 million, $476 million, $236 million and $76 million, respectively. Based on commodity prices at December 31, 2002, the Company had the intent and the ability to refinance most of the current maturities, and consequently it did not record $101 million of debt maturing in 2003 as part of the current portion of long-term debt.

On October 3, 2002, the Company issued $400 million principal amount of 5.05 percent notes with a maturity date of October 1, 2012. The net proceeds from the sale of the notes were primarily used to repay outstanding commercial paper borrowings that had been made during the year. At December 31, 2002, the Company had no outstanding commercial paper borrowings. During 2002, the Company also retired $172 million of maturing medium-term notes.

At December 31, 2002, the Company had $28 million outstanding on its Azerbaijan limited recourse loan. The Company completed the limited recourse project financing for its separate share of the Azerbaijan International Operating Company Early Oil Project under an International Finance Corporation and European Bank for Reconstruction and Development loan structure in 1998 for up to $77 million. The borrowing bears interest at a margin above London Interbank Offered Rates ("LIBOR"). The lenders' principal and interest payments are payable only out of the cash flow from the Company's sales of crude oil from the project.

Consolidated debt, at December 31, 2002, included $359 million of debt of the Company's Pure subsidiary. This debt primarily included $350 million in unsecured senior notes, which bear interest at 7.125 percent and mature in 2011. The notes were issued at a discount to their face value. As a result of the Company's acquisition of the Pure minority interests shares, long-term debt increased by $10 million reflecting the fair value of Pure's debt at the time of the purchase. Other Pure debt included $1 million outstanding under a $10 million working capital revolving credit facility. At the end of 2002, Pure had no borrowings outstanding under its 3-year $275 million revolving credit facility or its $125 million (reduced from $235 million in December 2002) 5-year revolving credit facility. Outstanding borrowings under both facilities were repaid in the fourth quarter of 2002 subsequent to the Company's acquisition of the remaining Pure minority interests shares. The Company cancelled both credit facilities in January 2003. The Company does not guarantee any of Pure's debt.

In February 2002, the Company's Northrock Resources Ltd. subsidiary redeemed its $35 million "Series A" and $40 million "Series B" senior U.S. dollar-denominated notes, which bore interest of 6.54 percent and 6.74 percent, respectively. The remaining $6 million of debt primarily consisted of capital leases.

The Company has two credit facilities in place: a $400 million 364-day credit agreement and a 5-year $600 million credit agreement. Borrowings under the bank credit agreements bear interest at a margin above LIBOR and the agreements call for a facility fee on the total commitment. The credit facilities provide for the termination of their loan commitments and require the prepayment of all outstanding borrowings in the event that (1) any person or group becomes the beneficial owner of more than 30 percent of the then outstanding voting stock of the Parent Company other than in a transaction having the approval of the Parent Company's board of directors, at least a majority of which are continuing directors, or (2) if continuing directors shall cease to constitute at least a majority of the board. The agreements do not have drawdown restrictions or prepayment obligations in the event of a credit rating downgrade. The interest rates charged on these credit facilities would vary marginally if a change occurred in the Company's credit rating. Both agreements limit the Company's debt to equity ratio to 70 percent, with the Company's convertible preferred securities included as equity in the ratio calculation. The Company had not drawn any funds under either credit facility at year-end 2002.

In December 2002, the Company also obtained a 3-year $295 million Canadian dollar-denominated non-revolving credit facility with a variable rate of interest. At December 31, 2002, the borrowings under the credit facility translated to $186 million, using applicable foreign exchange rates.

The Company had undrawn letters of credit at year-end 2002 that approximated $39 million. The majority of these letters of credit are maintained for operational needs and are renewed yearly.

NOTE 17 - ACCRUED ABANDONMENT, RESTORATION AND ENVIRONMENTAL LIABILITIES

At December 31, 2002 and 2001, the Company had accrued $490 million and $477 million, respectively, for the estimated future costs to abandon and remove wells and production facilities. The total costs for abandonments are predominantly accrued for on a unit-of-production basis. Under current accounting rules, these abandonment figures were estimated to be approximately $755 million at December 31, 2002 and $670 million at December 31, 2001. These estimates were derived in large part from abandonment cost studies performed by independent third-party firms and are used to calculate the amount to be amortized. See note 2 for additional discussion regarding the adoption of SFAS No. 143, new accounting pronouncement, effective January 1, 2003.

At December 31, 2002 and 2001, the Company's reserve for environmental remediation obligations totaled $245 million and $237 million, respectively, of which $113 million at year-end 2002 and $124 million at year-end 2001 were included in current liabilities. The reserve, at December 31, 2002 and 2001, included estimated probable future costs of $17 million and $12 million, respectively, for federal Superfund and comparable state-managed multi-party disposal sites; $37 million and $40 million, respectively, for active sites owned and/or controlled by the Company and utilized in its present operations; $104 million and $98 million, respectively, for formerly operated sites for which the Company has remediation obligations and sites related to businesses or operations that have been sold with contractual remediation or indemnification obligations; and $87 million in each year, for Company-owned or controlled sites where facilities have been closed or operations shut down.

NOTE 18 - OTHER FINANCIAL INFORMATION

The consolidated balance sheet included the following:

	At December 31,	
Millions of dollars	2002	2001
Other deferred credits and liabilities:		
Postretirement medical benefits	$ 223	$ 216
Pension and other employee benefits	195	92
Advances related to future production	110	105
Derivative liabilities	83	64
Prepaid forward sales	61	73
Reserves for litigation and other claims	45	72
Northrock (a)	6	32
Other	93	70
Total other deferred credits and liabilities	$ 816	$ 724
Allowances for doubtful accounts and notes receivables	$ 26	$ 146
Allowances for investments and long-term receivables	$ 3	$ 171

(a) Includes liability amounts associated with U.S. dollar forward contracts and commodity derivative contracts used by Northrock for general risk management purposes. Also includes liability amounts related to commodity sales contracts with below market prices and derivative contracts used for hedging purposes that were capitalized when Northrock was acquired.

In 2002, pension and other employee benefits included $103 million to recognize the minimum pension liability for the Company's Qualified Retirement Plan. This reflected the excess of the accumulated benefit obligation for vested current and former employees over the fair value of plan assets at December 31, 2002. See note 15 for a full discussion of the minimum pension liability for the Company's Qualified Retirement Plan.

In 2001, the allowances for doubtful accounts and notes receivables and the allowances for investments and long-term receivables primarily related to the Company's geothermal operations in Indonesia. In July 2002, the Company's UGI subsidiary and DSPL, a 50-percent equity investee of UGI, reached agreement over pricing and production issues at the Gunung Salak geothermal project in Indonesia with PLN and Pertamina, the Indonesian state-owned oil and natural gas company. Part of the new agreement provided for payment by PLN of a portion of the past due receivable balances to the Company while the Company forewent a portion of the receivables. The Company retained a receivable balance of $93 million plus interest that it expects to collect in full. The remaining outstanding receivables were written-off against the aforementioned allowances.

NOTE 19 – ADVANCE SALES OF NATURAL GAS

The Company entered into a long-term fixed price natural gas sales contract for the delivery of approximately 72 billion cubic feet of gas over a ten-year period beginning in January 1999 and ending in December 2008. In January 1999, the Company received a non-refundable payment of approximately $120 million pursuant to the contract. The Company will also receive a fixed monthly reservation fee over the life of the contract. The Company entered into a ten-year natural gas price swap agreement, which effectively refloated the fixed price that the Company received under the long-term natural gas sales contract. The Company did not dedicate a portion of its natural gas reserves to the contract and it has the option to satisfy contract delivery requirements with natural gas purchased from third parties. Accordingly, the obligation associated with the future delivery of the natural gas has been recorded as deferred revenue and will be amortized into revenue as scheduled deliveries of natural gas are made throughout the contract period. Of the remaining unamortized balance at year-end 2002, approximately $61 million related to deliveries scheduled to be made in the years 2004 through 2008 and was recorded in other deferred credits and liabilities on the consolidated balance sheet. Approximately $12 million was included in other current liabilities on the consolidated balance sheet, representing deliveries to be made in 2003. At December 31, 2002, the Company had in place an irrevocable surety bond in the amount of $93 million securing its performance under the sales contract.

NOTE 20 – MINORITY INTERESTS

At December 31, 2002, The Company's minority interests on the consolidated balance sheet were $275 million, a decrease of $174 million from 2001. This decrease was primarily due to the acquisition of the outstanding minority interest shares of the Company's Pure subsidiary. See note 3 for details on the acquisition.

In 1999, the Company contributed fixed-price overriding royalty interests from its working interest shares in certain oil and gas producing properties in the Gulf of Mexico to Spirit Energy 76 Development, L.P. ("Spirit LP"), a limited partnership. In exchange for its overriding royalty contributions, valued at $304 million, the Company received an initial general partnership interest in Spirit LP of approximately 55 percent. An unaffiliated investor contributed $250 million in cash to the partnership in exchange for an initial limited partnership interest of approximately 45 percent. The Company consolidates this partnership. The fixed-price overrides are subject to economic limitations of production from the affected fields. The limited partner is entitled to receive a priority allocation of profits and cash distributions. The limited partner's share has a maximum term of 20 years, but may terminate after six years, subject to certain conditions. If the Company's credit rating falls below Ba1 or BB+, then the priority return to the limited partner increases by two percent and the Company would have to provide cash collateral or a letter of credit for the $250 million. Almost all the minority interests in earnings were paid out to the limited partner as cash distributions and amounted to approximately $7 million and $16 million, for 2002 and 2001, respectively. The minority interest on the Company's consolidated balance sheet related to this transaction was approximately $252 million at December 31, 2002. The primary purpose of this transaction was to raise capital. In 2003, a new accounting rule, FASB Interpretation No. 46, related to variable interest entities will require that the Company consolidate the unaffiliated investor (see note 2). This is expected to result in a reclassification of $242 million from minority interests to long-term debt on the Company's consolidated balance sheet.

NOTE 21 – COMMITMENTS AND CONTINGENCIES

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

Environmental matters

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

As disclosed in note 17, at December 31, 2002, the Company had accrued $245 million for estimated future environmental assessment and remediation costs at various sites where liabilities for such costs are probable and reasonably estimable. The Company may also incur additional liabilities in the future at sites where remediation liabilities are probable but future environmental costs are not presently reasonably estimable because the sites have not been assessed or the assessments have not advanced to the stage where costs are reasonably estimable. At those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $245 million. The amount of such possible additional costs reflects the aggregate of the high end of the range of costs of feasible alternatives identified by the Company for those sites with respect to which investigation or feasibility studies have advanced to the stage of analyzing such alternatives. However, such estimated possible additional costs are not an estimate of the total remediation costs beyond the amounts reserved, because there are sites where the Company is not yet in a position to estimate all, or in some cases any, possible additional costs. Both the amounts reserved and estimates of possible additional costs may change in the near term, and in some cases could change substantially, as additional information becomes available regarding the nature and extent of site contamination, required or agreed-upon remediation methods and other actions by government agencies and private parties.

During 2002, cash payments of $114 million were applied against the reserves and $122 million in provisions were added to the reserves. Possible additional remediation costs decreased by approximately $15 million in 2002. The accrued costs and the possible additional costs are shown below in four categories of sites.

	At December 31, 2002	
Millions of dollars	Reserve	Possible Additional Costs
Superfund and similar sites	$ 17	$ 10
Active Company facilities	37	55
Company facilities sold with retained liabilities and former Company-operated sites	104	75
Inactive or closed Company facilities	87	105
Total reserve	$ 245	$ 245

The time frame 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 different future periods. Also, some of the work is dependent upon reaching agreements with regulatory agencies and/or other third parties on the scope of remediation work to be performed, who will perform the work, the timing of the work, who will pay for the work and other factors that may have an impact on the timing of the payments for amounts included in the reserve. For some sites, the remediation work will be performed by other parties, such as the current owners of the sites, and the Company has a contractual agreement to pay a share of the remediation costs. For these sites, the Company generally has less control over the timing of the work and consequently the timing of the associated payments. Based on available information, the Company estimates that the majority of the amounts included in the reserve will be paid within the next three to five years.

At the sites where the Company has a contractual agreement to share remediation costs with third parties, the reserve reflects the Company's estimated share 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 site. In many cases where the Company sold facilities or a business to a third party, sharing of remediation costs for those sites may be included in the sales agreement.

The contamination of the sites included in the above categories was primarily caused by the former operations at these sites. The "Company Facilities Sold and Former Company-Operated Sites" and "Inactive or Closed Company Facilities" categories include former Company refineries, transportation and distribution facilities and service stations. The required remediation of these sites is mainly for petroleum hydrocarbon contamination as the result of leaking tanks, pipelines or other equipment or impoundments that were used in these operations. Also, included in these categories are former oil and gas fields that the Company no longer operates. In most cases, these sites are contaminated with crude oil, oil field waste and other petroleum hydrocarbons. Contamination at other sites in this category was the result of former industrial chemical and polymers manufacturing and distribution facilities, agricultural chemical retail businesses, rare earth production and ferromolybdenum production operations.

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

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

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

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

At year-end 2002, the Company had received notification from the U.S. Environmental Protection Agency ("EPA") that the Company may be a PRP at 26 sites and may share certain liabilities at these sites. Of the total, two sites are under investigation and/or litigation and the Company's potential liability is not presently determinable and for one site the Company has denied responsibility. At one site, the Company has made a final settlement payment and is in the process of completing its involvement in the site. Of the remaining 22 sites, for those where probable costs can be reasonably estimated, reserves of $13 million have been established for future remediation and settlement costs.

Various state agencies and private parties had identified 23 other similar PRP sites. Four sites are under investigation and/or litigation and the Company's potential liability is not presently determinable. At three sites the Company's potential liability appears to be *de minimis*. At another site, the Company has made a final settlement payment and is in the process of completing its involvement in the sites. The Company has denied responsibility for two sites. Where probable costs can be reasonably estimated with respect to the remaining 13 sites, reserves of $4 million have been established for future remediation and settlement costs.

In 2002, provisions of $8 million were recorded for the "Superfund and Similar Sites" category. The provisions were primarily for the Company's estimated remaining share of oversight and monitoring costs related to the McColl Superfund site in Fullerton, California as the result of a federal appeals court overturning a 1998 court decision that held the federal government responsible for cleanup of the site because of its role in encouraging oil companies to produce gasoline during World War II. Payments for this category of sites were $3 million in 2002.

The sites discussed above exclude 112 sites where the Company's liability has been settled, or where the Company has no evidence of liability and there has been no further indication of liability by government agencies or third parties for at least a 12-month period.

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

Active Company facilities - Included in this category are:

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

The Company has a reserve of $37 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. Provisions of $12 million were recorded in 2002 for sites included in this category. These provisions were primarily for the estimated cost of studies, investigations and remediation activities at a molybdenum mine located in Questa, New Mexico, that is owned by the Company's Molycorp, Inc. ("Molycorp") subsidiary. Molycorp has been working cooperatively with the State of New Mexico and the U.S. Environmental Protection Agency to determine if past mining operations have had an adverse ecological impact on surface water and groundwater, and to identify remedial alternatives to mitigate any impact identified. Through the collaborative effort described above, it was determined that the scope of the environmental studies and investigations for the site needs to be expanded. The Company made payments of $15 million for this category of sites in 2002.

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

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

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

The Company has an aggregate reserve of $104 million for this group of sites. During 2002, provisions of $75 million were recorded for these sites. The provisions included revised remediation cost estimates that the Company received from the purchaser of service stations, bulk plants, terminals, refineries and pipelines that were part of the Company's former West Coast refining, marketing and transportation assets sold in 1997. Provisions for this category were also recorded as a result of revised cost estimates related to the cleanup of the Company's former service stations and distribution facilities throughout the U.S. and the estimated additional cost to cleanup contaminated areas that have been identified at a former oil field in Michigan that were previously operated by the Company. Cash payments of $69 million were made in 2002 for sites in this category.

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

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

Reserves of $87 million have been established for these types of facilities. Provisions of $27 million were recorded in 2002 for this category of sites. These provisions were principally for the cost of remediation work related to the decommissioning and decontamination of Molycorp's closed molybdenum and rare earth processing facilities in Washington and York, Pennsylvania. As a result of ongoing cooperative efforts between the Company and the Nuclear Regulatory Commission, a determination that probable additional volumes of low-level radioactive contaminated material, in excess of amounts previously estimated, needed to be removed at the York and Washington sites. Provisions were also recorded for revised cost estimates related to various remediation projects at the Company's former Guadalupe oil field on the central California coast which is also included in this category of sites. During 2002, $27 million in payments were made for sites in this category.

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

The Company also must provide financial assurance for future closure and post-closure costs of its RCRA-permitted facilities and for decommissioning costs at facilities that are under radioactive source materials licenses. Pursuant to a 1998 settlement agreement between the Company and the State of California (and the subsequent stipulated judgment entered by the Superior Court), the Company must provide financial assurance for anticipated costs of remediation activities at its inactive Guadalupe oil field. Also, pursuant to a 1995 settlement agreement between Molycorp and the California Department of Toxic Substances Control (and subsequent final judgment entered by the Superior Court), the Company must provide financial assurance for anticipated costs of disposing of certain wastes, as well as closing facilities associated with the handling of those wastes, at Molycorp's Mountain Pass, California, facility. At December 31, 2002, amounts included in the remediation reserve for these facilities totaled $93 million. At those sites where investigations or feasibility studies have advanced to the stage of analyzing alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $74 million. Although any possible additional costs for these sites are likely to be incurred at different times and over a period of many years, the Company believes that these obligations could have a material adverse effect on the Company's results of operations but are not expected to be material to the Company's consolidated financial condition or liquidity.

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

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

Certain Litigation and Claims

City of Santa Monica MTBE Lawsuit: In 2000, the City of Santa Monica, California (the "City") sued Shell Oil Company and other oil companies, including the Company, for contamination with methyl tertiary butyl ether ("MTBE") and a related chemical, tertiary butyl alcohol ("TBA"), of water pumped from the City's Charnock wellfield (*City of Santa Monica v Shell Oil Company et al,* California Superior Court, Orange County, Case No. 01CC04331). In 2001, Shell filed a cross-complaint against the Company and other oil companies, seeking the recovery of the funds it has expended to respond to the contamination. Further proceedings on this cross-complaint remain stayed.

The City's first amended complaint, filed in May 2002, alleges causes of action for strict liability (gasoline containing MTBE as a defective product designed, manufactured and sold without adequate warnings), negligence, trespass, public and private nuisance, declaratory relief and unfair competition. The City seeks damages, a declaration that the defendants are liable for all remedial actions, abatement of nuisance and injunctive relief. The City alleges that releases from sites of units of Shell, ChevronTexaco Corporation and ExxonMobil Corporation were the releases which caused the wellfield to be shut down. Releases from Company sites allegedly impacted the wellfield subsequently. The Company filed its answer to the City's complaint in August 2002.

In November 2002, the City, ChevronTexaco and ExxonMobil entered into a settlement (the "Chevron-Exxon Settlement"), subject to court approval, under which the two companies would pay the City $30 million and construct and operate a water treatment plant. The City's expert has estimated that the cost of treatment plant construction and operation could exceed $500 million, but other experts estimate the cost of aquifer restoration at $33 million. The City alleges $15 million in non-treatment facility damages. Future settlement and/or judgment amounts paid to the City from other defendants would go in part into an operating account, from which the two companies could be reimbursed for part or all of their treatment plant costs, as well as certain other costs. The court has scheduled a hearing for March 28, 2003 to consider approval of the settlement and its value as a credit against future recoveries from non-settling parties, which the settling parties have proposed at $40 million. The Company, Tosco Corporation (now part of Conoco Phillips) and other defendants, but not the Shell defendants, had been invited to participate in this settlement on terms which would have involved the Company paying the City $7.5 million and contributing to the costs of the treatment plant. Neither the Company nor the other invited defendants elected to participate on these terms.

In March 2003, the Company and two other defendants filed a joint opposition to the Chevron-Exxon Settlement. Based on a rigorous technical analysis of the data, the Company believes it has strong defenses to the allegations in the complaint, including the lack of evidence that its former service stations or activities are responsible for any contamination that has reached or threatens the wellfield. The Company also believes it has certain available defenses that the settling defendants and others may not have due to tolling agreements they entered into with the City; and, unlike the Shell defendants and the settling defendants, the Company is neither the object of punitive damages claims nor a cause of the wellfield's being originally shut down. The Company is also subject to potential partial responsibility for MTBE or TBA contamination in the wellfield arising from certain operations in the area of the Company's former gasoline marketing business that was sold in 1997, and is subject to potential liability, under a products liability theory, for gasoline it manufactured or sold that was ultimately distributed to area facilities operated by others. The Company's current analysis does not indicate any such liabilities are likely to be significant.

For several years prior to the City's suit, the EPA and the California Regional Water Quality Control Board have asserted jurisdiction over contamination of groundwater potentially affecting the wellfield, and these agencies have issued a number of orders under RCRA and state law to the Shell defendants and the other defendant oil companies, including the Company, with respect to both investigation of individual facilities and regional contamination, and requiring replacement of water lost to the City, which Shell is currently providing. In January 2003, the EPA Regional Administrator for Region IX wrote to the settling parties advising that it intended to issue a unilateral order to all parties whose releases have been demonstrated to contribute to contamination in the Charnock Sub-Basin ordering cleanup of MTBE and TBA "hot spots", unless a settlement in principle among all concerned parties is reached by March 31, 2003. The EPA also intends to defer to the City of Santa Monica's request to select and implement a wellhead treatment system. The Company received a copy of this letter. The Company has submitted to these agencies several technical analyses, which it believes demonstrate that its sites are not a part of any regional contamination problem, but, rather, present, at the most, localized issues which the Company, under agency oversight, has been successfully resolving.

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

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

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

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

In the Company Claim, the Company seeks declaratory relief in its favor against the allegations of Agrium set forth above and for judgment on the Retained Earnout in the amount of $16.6 million, together with interest accrued subsequent to May 2002.

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

The Company believes that certain portions of its disputes with Agrium are subject to binding arbitration under the terms of the GPSA. The Company initiated the Arbitration to determine the amount and delivery rate of the remaining gas supply available under that agreement. Agrium claims the dispute resolution provisions of the PSA supersede the arbitration provisions of the GPSA.

In January 2003, the state court ordered that the arbitration issues should be combined in the litigation but the scope of the court's order is unclear. Agrium has filed a motion to clarify the order with respect to the Arbitration. The Company is appealing the order and has filed a motion to stay discovery pending resolution of that appeal. The parties have agreed in principle to postpone the Arbitration, pending resolution of the appeal, and to stay discovery until May 1, 2003 (except with respect to the environmental issues) in order to allow settlement discussions to proceed.

Petrobangla Claim: In July 2002, the Company's subsidiary Unocal Bangladesh Blocks Thirteen and Fourteen, Ltd. ("Unocal Blocks 13 and 14 Ltd.") (which was acquired in 1999 from Occidental Petroleum Corporation and, prior to the recent completion of Bangladesh name-change formalities, was still known in Bangladesh as Occidental of Bangladesh Ltd.) ("OBL"), received from the Bangladesh Oil, Gas & Mineral Corporation ("Petrobangla") a letter claiming, on behalf of the Bangladesh government and Petrobangla, compensation allegedly due in the amount of $685 million for 246 BCF of recoverable natural gas allegedly "lost and damaged" in a 1997 blowout and ensuing fire during the drilling by OBL, as operator, of the Moulavi Bazar #1 ("MB #1") exploration well on the Blocks 13 and 14 PSC area in Northeast Bangladesh. The Company and OBL believe that the claim vastly overstates the amount of recoverable gas involved in the blowout.

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

Nuevo Energy Claim: In March 2003, the Company received a letter from Nuevo Energy Company regarding a contingent payment for the year 2002 owed by Nuevo to the Company under the terms of the 1996 Asset Purchase Agreement pursuant to which Nuevo purchased substantially all of the Company's operating California oil and gas properties. Notwithstanding that Nuevo had notified the Company in January 2003 of its estimate of the payment for 2002, Nuevo now claims that the long-standing calculation methodology for this payment was incorrect, that no payment should be due for 2002, and that the payment made for 2001 should be refunded. The Company disputes Nuevo's new position and expects to commence litigation in the event that the 2002 payment is not received. The potential cash exposure to the Company is $27 million.

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

Tax matters

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

Pure Resources, Inc. Employment and Severance Agreements

As part of the acquisition of the Pure minority interests shares by the Company at the end of October 2002 (see note 20), the Pure stock subject to repurchase by Pure, which was owed to Pure officers, was replaced by Parent Company stock and the repurchase requirement was cancelled. At December 31, 2001, the repurchase amount under these agreements was approximately $70 million.

Guarantees Related to Assets or Obligations of Third Parties

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

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

The Company has accrued probable and reasonably estimable assessment and remediation costs for the locations covered under these guarantees. These amounts are included in the "Company facilities sold with retained liabilities and former Company-operated sites" category of the Company's reserve for environmental remediation obligations. At December 31, 2002, the reserve for this category totaled $104 million. For those sites where investigations or feasibility studies have advanced to the stage of analyzing feasible alternative remedies and/or ranges of costs, the Company estimates that it could incur possible additional remediation costs aggregating approximately $75 million. See the discussion elsewhere in this footnote for additional information regarding this category.

The Company has guaranteed the debt of certain joint ventures accounted for by the equity method. The majority of this debt matures evenly through the year 2014. The maximum potential amount of future payments the Company could be required to make is approximately $25 million.

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

Financial Assurance for Union Oil Company of California Obligations

In the normal course of business, the Company has performance obligations which are secured, in whole or in part, by surety bonds or letters of credit. These obligations primarily cover self-insurance, site restoration, dismantlement and other programs where governmental organizations require such support. These surety bonds and letters of credit are issued by financial institutions but are funded by the Company if exercised. At December 31, 2002, the Company had obtained various surety bonds for approximately $215 million. These surety bonds included a bond for $93 million securing the Company's performance under a fixed price natural gas sales contract for the delivery of 72 billion cubic feet of gas over a ten-year period that began in January of 1999 and will end in December of 2008 and approximately $122 million in various other routine performance bonds held by local, city, state and federal agencies. The Company also had obtained approximately $39 million in standby letters of credit at December 31, 2002. The Company has entered into indemnification obligations in favor of the providers of these surety bonds and letters of credit. In addition, the

Company has various other guarantees for approximately $545 million. Guarantees for approximately $332 million of this amount would require the Company to obtain a surety bond or a letter of credit or establish a trust fund if its credit rating were to drop below investment grade--that is BBB- or Baa3 from Standard & Poor's Ratings Services and Moody's Investors Service, Inc., respectively. Approximately $160 million of the surety bonds, letters of credit and other guarantees that the Company is required to obtain or issue reflect obligations that are already included on the consolidated balance sheet in other current liabilities and other deferred credits. The surety bonds, letters of credit and other guarantees may also reflect some of the possible additional remediation liabilities discussed earlier in this note.

Approximately $134 million of the $545 million in guarantees mentioned in the previous paragraph represents financial assurance given by the Company on behalf of its Molycorp subsidiary relating to permits covering operations and discharges from its Questa, New Mexico, molybdenum mine. The Company's financial assurance is for the completion of temporary closure plans (required only upon cessation of operations) and other obligations required under the terms of the permits. The costs associated with the financial assurance are based on estimations provided by agencies of the state of New Mexico.

Other matters

The Company has a lease agreement relating to its *Discoverer Spirit* deepwater drillship, with a remaining term of approximately two years and nine months at December 31, 2002. In 2001, the Company signed a sublease agreement with a third party for a period that began in December 2001 and ended in mid-September 2002. Under the provisions of that agreement, the third party assumed all of the lease payments to the lessor during the sublease period. The drillship has a current minimum daily rate of approximately $224,000. The future remaining minimum lease payment obligation was approximately $222 million at December 31, 2002.

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

NOTE 22 - CAPITAL STOCK

Common Stock

Authorized - 260,000,000

$2-1/12 Par value per share

	2002	2001	2000
Outstanding at beginning of year	1,000	1,000	1,000
Outstanding at end of year	1,000	1,000	1,000

At December 31, 2002, the Company had 260,000,000 shares of $2-1/12 par value common stock authorized. Of this authorized amount, 1,000 shares were outstanding at year-end 2002 and 2001. All of the outstanding stock of Union Oil Company of California was owned by the Parent Company at December 31, 2002 and 2001.

NOTE 23 – LOANS TO CERTAIN OFFICERS AND KEY EMPLOYEES

The Company's Pure subsidiary had a loan program for certain of its officers and key employees. At December 31, 2002, loans under this program totaled $2 million and were also reflected as a reduction to shareholder's equity on the consolidated balance sheet. At December 31, 2001, loans under this program totaled $7 million. This decrease of $5 million primarily reflects loan repayments by certain former officers and key employees of Pure that departed after the Company purchased the minority interests share remaining in Pure (see note 3). Most of the remaining $2 million balance will be repaid in early 2003.

NOTE 24 - FINANCIAL INSTRUMENTS AND COMMODITY HEDGING

The Company does not generally hold or issue financial instruments for trading purposes other than those that are hydrocarbon based. The counterparties to the Company's financial instruments include regulated exchanges, international and domestic financial institutions and other industrial companies. All of the counterparties to the Company's financial instruments must pass certain credit requirements deemed sufficient by management before trading physical commodities or financial instruments with the Company.

Interest rate contracts – The Company enters into interest rate swap contracts to manage its debt with the objective of minimizing the volatility and magnitude of the Company's borrowing costs. The Company may also enter into interest rate option contracts to protect its interest rate positions, depending on market conditions. At December 31, 2002, the Company had approximately $26 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, $4 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 by the Company from time to time to manage its exposures to adverse impacts of foreign currency fluctuations on recognized obligations and anticipated transactions. At December 31, 2002, the Company had approximately $1 million of after-tax deferred gains in accumulated other comprehensive income on the consolidated balance sheet related to cash flow hedges for future foreign currency denominated payment obligations through December 2003. All of this amount is expected to be reclassified to the consolidated earnings statement during the next twelve months.

Commodity hedging activities – The Company uses hydrocarbon derivatives to mitigate the Company's overall exposure to fluctuations in hydrocarbon commodity prices. During 2002, the Company recognized about $1 million in after-tax losses for the ineffectiveness of both cash flow and fair value hedges. At December 31, 2002, the Company had approximately $21 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 January 2003 through October 2004. Of this amount, approximately $14 million in 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 the Company's long-term debt were $3,352 million and $2,809 million at year-end 2002 and 2001, respectively. Fair values were based on the discounted amounts of future cash outflows using the rates offered to the Company for debt with similar remaining maturities.

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

During 2002, the Company took appropriate actions to help mitigate credit exposure to counterparties whose creditworthiness had deteriorated. In some cases, counterparty credit lines were reduced or rescinded. In other instances, the Company obtained credit assurances in the form of prepayments, letters of credit or guarantees to support the credit decision.

The majority of the Company's trade receivables balance at December 31, 2002, was attributable to the sale of crude oil and natural gas produced by the Company or purchased by the Company for resale. The Company has receivable concentrations for its crude oil and natural gas sales and geothermal steam and related electricity sales in certain Asian countries that are subject to currency fluctuations and other factors affecting the region.

At December 31, 2002, approximately $95 million, or 10 percent, of the Company's net accounts receivable balance was due from PTT Public Co., Ltd. This amount primarily represented payments due for sales of natural gas from the Company's fields in the Gulf of Thailand and offshore Myanmar. No other individual crude oil or natural gas customer accounted for 10 percent or more of the Company's consolidated net trade receivable balance at December 31, 2002.

The Company continues to work with the government of Bangladesh and Petrobangla, the state oil and gas company, to develop additional reserves and export natural gas to markets in neighboring India. At December 31, 2002, the Company's business unit in Bangladesh had a gross receivable balance of approximately $27 million relating to invoices billed for natural gas and condensate sales to Petrobangla. Approximately $22 million of the outstanding balance represented past due amounts and accrued interest for invoices covering August 2002 through November 2002. Generally, invoices, when paid, have been paid in full. The Company continues to work with Petrobangla and the government of Bangladesh regarding the collection of the outstanding receivables.

NOTE 25 – SEGMENT AND GEOGRAPHIC DATA

The Company's reportable segments are as follows:

Exploration and Production Segment - This segment includes the Company's North American and International oil and gas operations. North America includes the U.S. Lower 48, Alaska and Canada oil and gas operations. The Company's International operations include activities outside of North America and are categorized under Far East and Other International. The Company's International Far East operations include production activities in Thailand, Indonesia and Myanmar. The Company's Other International operations include production in Bangladesh, the Netherlands, Azerbaijan, the Democratic Republic of Congo and Brazil. The Company is also involved in exploration and development activities in Asia, Australia, Brazil and West Africa. In 2002, $790 million, or approximately 15 percent, of the Company's total external sales and operating revenues were attributable to the sale of natural gas and condensate, produced offshore Thailand and Myanmar, to PTT. In 2002, the Company booked $92 million in goodwill related to two acquisitions in North America, including $80 million in conjunction with the acquisition of the minority interests of Pure. The Company recognized $30 million in goodwill related to one acquisition in North America in 2001. The Company periodically, and at a minimum annually, tests for impairment of goodwill. As of December 31, 2002, no such impairments had been recorded.

Trade Segment - The Trade segment externally markets most of the Company's worldwide liquids production, excluding that of Pure, and North American natural gas production, excluding that of Pure and the Alaska business unit. It is also responsible for executing various derivative contracts on behalf of the Company's Exploration and Production segment in order to manage the Company's exposure to commodity price changes. The Trade segment also purchases crude oil, condensate and natural gas from certain royalty owners, joint venture partners and unaffiliated oil and gas producing and trading companies for resale. In addition, the segment trades hydrocarbon derivative instruments, for non-hedge purposes for its own account subject to internal restrictions, including value at risk limits. The segment also purchases limited amounts of physical inventories held for energy trading purposes.

Midstream Segment - The Midstream segment is comprised of the Pipelines business, which principally encompasses the Company's worldwide equity interests in various petroleum pipeline companies and wholly-owned pipeline systems throughout the U.S., and the Company's North America gas storage business.

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

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

The following tables present the Company's financial data by business segment and geographic area of operations. Intersegment revenues, which are eliminated upon consolidation, in business segment data are primarily sales from the Exploration and Production segment to the Trade segment. Intersegment sales prices approximate market prices. The revenues presented in the geographic area disclosure table primarily represent sales of crude oil and natural gas produced within the countries or regions shown.

SEGMENT DATA

2002 Segment Information
Millions of dollars

	Exploration & Production					Trade
	North America			International		
	U.S. Lower 48	Alaska	Canada	Far East	Other	
Sales & operating revenues	$ 509	$ 251	$ 207	$ 1,062	$ 151	$ 2,524
Other income (loss) (a)	(27)	-	(1)	1	1	(1)
Inter-segment revenues	825	-	-	238	116	1
Total	1,307	251	206	1,301	268	2,524
Depreciation, depletion & amortization	479	63	97	239	48	1
Impairments	17	24	-	-	-	-
Dry hole costs	64	17	9	23	5	-
Exploration expense						
Amortization of exploratory leases	55	1	18	1	23	-
Earnings (loss) from equity investments	2	-	-	33	7	2
Earnings (loss) from continuing operations						
before income taxes and minority interests	47	-	3	731	103	6
Income taxes (benefit)	6	-	3	300	31	2
Minority interests	15	-	-	-	-	-
Earnings (loss) from continuing operations	26	-	-	431	72	4
Net earnings (loss)	26	-	-	431	72	4
Capital expenditures and acquisitions	544	72	147	626	157	-
Assets	3,347	326	1,113	2,861	821	304
Equity investments	146	-	-	23	174	14

	Midstream	Geothermal & Power Operations	Corporate & Other				Total
			Administrative & General	Net Interest Expense	Environmental & Litigation	Other (b)	
Sales & operating revenues	$ 276	$ 120	$ -	$ -	$ -	$ 124	$ 5,224
Other income (loss) (a)	52	(3)	-	17	-	34	73
Inter-segment revenues	12	-	-	-	-	(1,192)	-
Total	340	117	-	17	-	(1,034)	5,297
Depreciation, depletion & amortization	11	18	-	-	-	17	973
Impairments	4	-	-	-	-	2	47
Dry hole costs	-	-	-	-	-	-	118
Exploration expense							
Amortization of exploratory leases	-	-	-	-	-	-	98
Earnings (loss) from equity investments	63	(1)	-	-	-	48	154
Earnings (loss) from continuing operations							
before income taxes and minority interests	143	51	(115)	(163)	(119)	(44)	643
Income taxes (benefit)	39	21	(38)	(29)	(43)	(9)	283
Minority interests	-	-	-	(6)	-	(3)	6
Earnings (loss) from continuing operations	104	30	(77)	(128)	(76)	(32)	354
Discontinued operations (net)	-	-	-	-	-	1	1
Cumulative effect of accounting changes	-	-	-	-	-	-	-
Net earnings (loss)	104	30	(77)	(128)	(76)	(31)	355
Capital expenditures and acquisitions	71	14	-	-	-	39	1,670
Assets	511	526	-	-	-	962	10,771
Equity investments	215	36	-	-	-	78	686

(a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets
(b) Includes eliminations and consolidation adjustments

SEGMENT DATA (Continued)

2001 Segment Information *Millions of dollars*	**Exploration & Production**					**Trade**
	North America			International		
	U.S. Lower 48	Alaska	Canada	Far East	Other	
Sales & operating revenues	$ 626	$ 282	$ 239	$ 1,013	$ 138	$ 3,856
Other income (loss) (a)	28	-	(1)	27	(35)	(1)
Inter-segment revenues	1,438	-	-	199	112	1
Total	2,092	282	238	1,239	215	3,856
Depreciation, depletion & amortization	505	53	104	212	40	1
Impairments	118	-	-	-	-	-
Dry hole costs	99	-	11	25	40	-
Exploration expense						
Amortization of exploratory leases	51	-	21	9	14	-
Earnings (loss) from equity investments	(11)	-	-	39	(2)	-
Earnings (loss) from continuing operations						
before income taxes and minority interests	643	87	20	700	40	8
Income taxes (benefit)	221	32	10	284	13	2
Minority interests	47	-	-	-	-	-
Earnings (loss) from continuing operations	375	55	10	416	27	6
Net earnings (loss)	375	55	10	416	27	6
Capital expenditures and acquisitions	1,414	81	206	425	148	-
Assets	3,345	344	1,015	2,463	741	156
Equity investments	117	-	-	24	172	11

	Midstream	**Geothermal & Power Operations**	**Corporate & Other**				**Total**
			Administrative & General	Net Interest Expense	Environmental & Litigation	Other (b)	
Sales & operating revenues	$ 242	$ 181	$ -	$ -	$ -	$ 131	$ 6,708
Other income (loss) (a)	2	16	-	24	-	23	83
Inter-segment revenues	8	-	-	-	-	(1,758)	-
Total	252	197	-	24	-	(1,604)	6,791
Depreciation, depletion & amortization	14	14	-	-	-	24	967
Impairments	-	-	-	-	-	-	118
Dry hole costs	-	-	-	-	-	-	175
Exploration expense							
Amortization of exploratory leases	-	-	-	-	-	-	95
Earnings (loss) from equity investments	62	1	-	-	-	55	144
Earnings (loss) from continuing operations							
before income taxes and minority interests	69	17	(115)	(168)	(166)	(11)	1,124
Income taxes (benefit)	15	6	(39)	(31)	(62)	6	457
Minority interests	-	-	-	(6)	-	-	41
Earnings (loss) from continuing operations	54	11	(76)	(131)	(104)	(17)	626
Discontinued operations (net)	-	-	-	-	-	17	17
Cumulative effect of accounting changes	-	-	-	-	-	(1)	(1)
Net earnings (loss)	54	11	(76)	(131)	(104)	(1)	642
Capital expenditures and acquisitions	41	7	-	-	-	51	2,373
Assets	479	594	-	-	-	1,313	10,450
Equity investments	187	54	-	-	-	60	625

(a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets.

(b) Includes eliminations and consolidation adjustments.

SEGMENT DATA (Continued)

2000 Segment Information
Millions of dollars

	Exploration & Production					Trade
	North America			International		
	U S Lower 48	Alaska	Canada	Far East	Other	
Sales & operating revenues	$ 298	$ 254	$ 168	$ 1,018	$ 145	$ 6,693
Other income (loss) (a)	63	-	2	16	(22)	-
Inter-segment revenues	1,528	48	-	207	98	8
Total	1,889	302	170	1,241	221	6,701
Depreciation, depletion & amortization	370	57	90	212	39	1
Impairments	13	-	-	-	-	-
Dry hole costs	85	3	7	58	3	-
Exploration expense						
Amortization of exploratory leases	44	-	19	9	11	-
Earnings (loss) from equity investments	18	-	-	19	(1)	-
Earnings (loss) from continuing operations						
before income taxes and minority interests	756	146	(94)	691	62	6
Income taxes (benefit)	267	54	(80)	274	16	1
Minority interests	39	-	(20)	-	-	-
Earnings (loss) from continuing operations	450	92	6	417	46	5
Net earnings (loss)	450	92	6	417	46	5
Capital expenditures and acquisitions	628	34	325	482	62	1
Assets	2,701	315	1,119	2,251	603	655
Equity investments	128	-	3	143	27	10

	Midstream	Geothermal & Power Operations	Corporate & Other				Total
			Administrative & General	Net Interest Expense	Environmental & Litigation	Other (b)	
Sales & operating revenues	$ 51	$ 161	$ -	$ -	$ -	$ 168	$ 8,956
Other income (loss) (a)	12	17	-	31	-	132	251
Inter-segment revenues	11	-	-	-	-	(1,900)	-
Total	74	178	-	31	-	(1,600)	9,207
Depreciation, depletion & amortization	14	15	-	-	-	23	821
Impairments	-	-	-	-	-	53	66
Dry hole costs	-	-	-	-	-	-	156
Exploration expense							
Amortization of exploratory leases	-	2	-	-	-	-	85
Earnings (loss) from equity investments	57	(2)	-	-	-	43	134
Earnings (loss) from continuing operations							
before income taxes and minority interests	83	45	(121)	(178)	(134)	-	1,262
Income taxes (benefit)	21	21	(36)	(30)	(50)	42	500
Minority interests	-	-	-	(3)	-	-	16
Earnings (loss) from continuing operations	62	24	(85)	(145)	(84)	(42)	746
Discontinued operations (net)	-	-	-	-	-	37	37
Net earnings (loss)	62	24	(85)	(145)	(84)	(5)	783
Capital expenditures and acquisitions (c)	16	18	-	-	-	54	1,620
Assets	316	574	-	-	-	1,489	10,023
Equity investments	189	50	-	-	-	68	618

(a) Includes interest, dividends and miscellaneous income, and gain (loss) on sales of assets

(b) Includes eliminations and consolidation adjustments

(c) Includes capital expenditures for discontinued operations (agricultural products) of $14 million.

GEOGRAPHIC INFORMATION

2002 Geographic Disclosures

Millions of dollars	U. S.	Canada	Thailand	Indonesia	Other Foreign	Corporate & Other	Total
Sales and operating revenues from continuing operations	$ 2,785	$ 442	$ 789	$ 644	$ 535	$ 29	$ 5,224
Long lived assets:							
Gross	10,378	1,511	3,316	2,887	1,876	177	20,145
Net	3,584	1,064	1,123	1,278	736	83	7,868

2001 Geographic Disclosures

Millions of dollars	U. S	Canada	Thailand	Indonesia	Other Foreign	Corporate & Other	Total
Sales and operating revenues from continuing operations	$ 4,418	$ 442	$ 683	$ 613	$ 529	$ 23	$ 6,708
Long lived assets:							
Gross	10,161	1,387	2,982	2,541	1,857	234	19,162
Net	3,637	1,024	1,016	1,002	723	82	7,484

2000 Geographic Disclosures

Millions of dollars	U. S	Canada	Thailand	Indonesia	Other Foreign	Corporate & Other	Total
Sales and operating revenues from continuing operations	$ 6,956	$ 184	$ 735	$ 700	$ 380	$ 1	$ 8,956
Long lived assets							
Gross	8,620	1,200	2,803	2,390	1,793	372	17,178
Net	2,699	975	967	921	720	151	6,433

SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

Results of Operations

Results of operations of oil and gas exploration and production activities are shown below. Sales revenues are shown net of purchases. Other revenues primarily include gains or losses on sales of oil and gas properties and miscellaneous rental income. Production costs include costs incurred to operate and maintain wells and related facilities, operating overhead and taxes other than income. Exploration expenses consist of geological and geophysical costs, leasehold rentals, amortization of exploratory leases and dry hole costs. Depreciation, depletion and amortization expense includes impairments and provisions of estimated future abandonment liabilities. Other operating expenses primarily include administrative and general expense. Income tax expense is based on the tax effects arising from the operations. Results of operations do not include general corporate overhead, interest costs, minority interests expense or the activities of the Trade business segment.

	North America			International		
Millions of dollars	U.S. Lower 48	Alaska	Canada	Far East	Other	Total
2002						
Sales						
To public	$ 338	$ 249	$ 217	$ 1,060	$ 137	$ 2,001
Intercompany	825	-	-	238	116	1,179
Other revenues	5	2	-	2	3	12
Total	1,168	251	217	1,300	256	3,192
Production costs	265	81	52	176	46	620
Exploration expenses	201	23	34	58	47	363
Depreciation, depletion and amortization	496	87	97	239	48	967
Other operating expenses	161	60	17	131	19	388
Pre-tax results of operations	45	-	17	696	96	854
Income taxes	5	-	7	287	29	328
Results of operations	$ 40	$ -	$ 10	$ 409	$ 67	$ 526
Results of equity investees (a)	2	-	-	33	7	42
Total	$ 42	$ -	$ 10	$ 442	$ 74	$ 568
(a) Union Oil's proportional shares of investees accounted for by the equity method.						
2001						
Sales						
To public	$ 374	$ 278	$ 223	$ 1,029	$ 129	$ 2,033
Intercompany	1,439	-	-	199	111	1,749
Other revenues	51	4	-	(1)	(2)	52
Total	1,864	282	223	1,227	238	3,834
Production costs	278	86	54	156	45	619
Exploration expenses	223	2	40	84	78	427
Depreciation, depletion and amortization	623	53	104	212	40	1,032
Other operating expenses	86	54	20	114	34	308
Pre-tax results of operations	654	87	5	661	41	1,448
Income taxes	221	32	4	284	13	554
Results of operations	$ 433	$ 55	$ 1	$ 377	$ 28	$ 894
Results of equity investees (a)	(11)	-	-	39	(1)	27
Total	$ 422	$ 55	$ 1	$ 416	$ 27	$ 921

(a) Union Oil's proportional shares of investees accounted for by the equity method.

Results of Operations (continued)

Millions of dollars	North America			International		
	U.S. Lower 48	Alaska	Canada	Far East	Other	Total
2000						
Sales						
To public	$ 109	$ 260	$ 198	$ 1,009	$ 126	$ 1,702
Intercompany	1,442	47	-	207	98	1,794
Other revenues	75	3	31	9	1	119
Total	1,626	310	229	1,225	225	3,615
Production costs	208	80	51	152	45	536
Exploration expenses	219	6	33	108	47	413
Depreciation, depletion and amortization	383	57	90	212	39	781
Other operating expenses	78	21	15	80	32	226
Pre-tax results of operations	738	146	40	673	62	1,659
Income taxes	267	54	(20)	274	16	591
Results of operations	$ 471	$ 92	$ 60	$ 399	$ 46	$ 1,068
Results of equity investees (a)	18	-	-	18	-	36
Total	$ 489	$ 92	$ 60	$ 417	$ 46	$ 1,104

(a) Union Oil's proportional shares of investees accounted for by the equity method.

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities, both capitalized and charged to expense, are shown below. Data for the Company's capitalized costs related to oil and gas exploration and production activities are presented in note 14.

	North America			International		
Millions of dollars	U.S. Lower 48	Alaska	Canada	Far East	Other	Total (a)
2002						
Property acquisition						
Proved (b)	$ 110	$ -	$ 45	$ -	$ -	$ 155
Unproved (c)	55	-	5	22	3	85
Exploration	246	20	31	110	22	429
Development	292	57	79	564	147	1,139
Costs incurred by equity investees (d)	48	-	-	-	3	51
2001						
Property acquisition						
Proved (e) (f) (g)	$ 725	$ -	$ 121	$ -	$ -	$ 846
Unproved	103	4	16	2	1	126
Exploration	412	13	34	115	59	633
Development	361	67	66	374	37	905
Costs incurred by equity investees (d)	86	-	-	-	78	164
2000						
Property acquisition						
Proved (h) (i)	$ 312	$ -	$ 346	$ 157	$ 18	$ 833
Unproved	57	-	6	6	1	70
Exploration	294	6	34	134	46	514
Development	279	30	70	237	33	649
Costs incurred by equity investees (d)	103	-	-	-	-	103

(a) Includes costs attributable to outstanding minority interests in consolidated subsidiaries of:

2002	$	63
2001	$	305
2000	$	154

(b) U S. Lower 48 includes $73 million for the increased proved property basis resulting from the acquisition of the Pure minority interest shares.

(c) U.S Lower 48 includes $48 million for the increased unproved property basis resulting from the acquisition of the Pure minority interest shares

(d) Represents Union Oil's proportional shares of costs incurred by investees accounted for by the equity method

(e) U.S. Lower 48 includes $267 million cash for the acquisition by Pure of certain assets from International Paper Company.

(f) U.S. Lower 48 includes $173 million of cash, $87 million of net debt, $31 million of hedge liabilities and $11 million of other net liabilities assumed for the acquisition by Pure of the common stock of Hallwood Energy Corporation.

(g) Canada includes $93 million cash, $20 million of net debt and $4 million of other net liabilities for the acquisition of the common stock of Tethys Energy Inc.

(h) U.S Lower 48 includes $244 million for the acquisition by Pure of the common stock of Titan Exploration, Inc.

(i) Canada includes $161 million of cash, $82 million of net debt and $65 million of hedge liabilities for the remaining interest in Northrock Resources Ltd