CONTINENTAL RESOURCES INC
Form 10-Q
May 17, 2004

United States
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________to _________

Commission File Number: 333-61547

CONTINENTAL RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Oklahoma	73-0767549
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

302 N. Independence, Suite 300, Enid, Oklahoma	73701
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (580) 233-8955

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [ ] No [X]

The Registrant is not subject to the filing requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, but files reports required by those sections pursuant to contractual obligation requirements.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act.) Yes [ ] No [X]

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	Outstanding as of May 14, 2004
Common Stock, $.01 par value	14,368,919 shares

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PART I. Financial Information

ITEM 1. FINANCIAL STATEMENTS

CONTINENTAL RESOURCES, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

Assets	December 31, 2003	March 31, 2004
Current assets:		(Unaudited)
Cash and cash equivalents	$ 2,277	$ 1,968
Accounts receivable:		
Oil and gas sales	19,035	18,964
Joint interest and other, net	13,577	11,196

Inventories	5,465	5,168
Prepaid expenses	336	144
Fair value of derivative contracts	151	40
Total current assets	40,841	37,480
Property and equipment, at cost:		
Oil and gas properties, based on successful efforts accounting	601,325	616,546
Gas gathering and processing facilities	49,600	50,882
Service properties, equipment and other	19,515	19,629
Total property and equipment	670,440	687,057
Less accumulated depreciation, depletion and amortization	231,008	242,076
Net property and equipment	439,432	444,981
Other assets:		
Debt issuance costs, net	4,707	4,344
Other assets	8	8
Total other assets	4,715	4,352
Total assets	$ 484,988	$ 486,813
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 27,950	$ 26,614
Current portion of long-term debt	5,776	5,776
Revenues and royalties payable	8,250	7,935
Accrued liabilities:		
Interest	6,312	3,054
Other	7,212	6,330
Fair value of derivative contracts	640	1,433
Total current liabilities	56,140	51,142
Long-term debt, net of current portion	285,144	291,199
Asset retirement obligation	26,608	26,891
Other noncurrent liabilities	164	166
Stockholders' equity:		
Preferred stock, $0.01 par value, 1,000,000 shares authorized, no shares issued and outstanding	-	-
Common stock, $0.01 par value, 20,000,000 shares authorized, 14,368,919 shares issued and outstanding	144	144
Additional paid-in-capital	25,087	25,087
Retained earnings	92,190	93,181
Accumulated other comprehensive income	(489)	(997)
Total stockholders' equity	116,932	117,415
Total liabilities and stockholders' equity	$ 484,988	$ 486,813

The accompanying notes are an integral part of these condensed consolidated financial statements.

CONTINENTAL RESOURCES, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED INCOME STATEMENTS
(Unaudited)
(Dollars in thousands, except share data)

	Three Months Ended March	
	2003	
Revenues:	(restated)	
Oil and gas sales	$ 35,722	$
Crude oil marketing and trading	40,595	
Change in derivative fair value	303	
Gas gathering, marketing and processing	9,725	
Oil and gas service operations	1,882	
Total revenues	88,227	
Operating costs and expenses:		
Production	8,631	
Production taxes	2,674	
Exploration	1,502	
Crude oil marketing and trading	40,484	
Gas gathering, marketing and processing	8,828	
Oil and gas service operations	1,960	
Depreciation, depletion and amortization of oil and gas properties	8,302	
Depreciation and amortization of other property and equipment	1,148	
Property impairments	1,276	
Asset retirement obligation accretion	352	
General and administrative	2,838	
Total operating costs and expenses	77,995	
Operating income	10,232	
Other income (expenses):		
Interest income	32	
Interest expense	(4,951)	
Other income, net	37	
Loss on sale of assets	(8)	
Total other income (expense)	(4,890)	
Income before change in accounting principle	5,342	
Cumulative effect of change in accounting principle	2,162	
Net income	$ 7,504	$
Basic earnings per common share:		
Earnings before cumulative effect of accounting change	$ 0.37	$
Cumulative effect of accounting change	0.15	
Basic	$ 0.52	$
Diluted earnings per common share:		
Earnings before cumulative effect of accounting change	$ 0.37	$
Cumulative effect of accounting change	0.15	

Diluted	$ 0.52	$

The accompanying notes are an integral part of these condensed consolidated financial statements.

CONTINENTAL RESOURCES, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(Dollars in thousands)

	Three Months Ended Ma	
	2003	
	(restated)	
Cash flows from operating activities:		
Net income	$ 7,504	$
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion and amortization	9,450	
Accretion of asset retirement obligation	352	
Impairment of properties	1,276	
Change in derivative fair value	(303)	
Amortization of debt issuance costs	402	
Loss on sale of assets	8	
Change in accounting principle	(2,162)	
Dry hole costs	830	
Cash provided by (used in) changes in assets and liabilities-		
Accounts receivable	(3,637)	
Inventories	(836)	
Prepaid expenses	132	
Accounts payable	1,027	
Revenues and royalties payable	2,067	
Accrued liabilities and other	(2,784)	
Other noncurrent assets	89	
Other noncurrent liabilities	12	
Net cash provided by operating activities	13,427	
Cash flows from investing activities:		
Exploration and development	(26,092)	
Gas gathering and processing facilities and service properties, equipment and other	(1,564)	
Purchase of oil and gas properties	(82)	
Proceeds from sale of assets	56	
Net cash used in investing activities	(27,682)	
Cash flows from financing activities:		
Proceeds from line of credit and other	18,500	
Repayment of debt	(600)	
Debt issuance costs	-	
Net cash provided by financing activities	17,900	
Net increase (decrease) in cash	3,645	
Cash and cash equivalents, beginning of year	2,520	

Cash and cash equivalents, end of quarter	$ 6,165	$

The accompanying notes are an integral part of these condensed consolidated financial statements.

CONTINENTAL RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. CONTINENTAL RESOURCES, INC.'S FINANCIAL STATEMENTS:

In the opinion of Continental Resources, Inc., or CRI or the Company, the accompanying unaudited condensed consolidated financial statements contain all adjustments necessary to present fairly the Company's financial position as of March 31, 2004, the results of operations and cash flows for the three months ended March 31, 2003 and 2004. Such adjustments are of a normal recurring nature. The unaudited condensed consolidated financial statements for the interim periods presented do not contain all information required by accounting principles generally accepted in the United States. The results of operations for any interim period are not necessarily indicative of the results of operations for the entire year. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's annual report on form 10-K for the year ended December 31, 2003.

In 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost should be allocated to expense using a systematic and rational method and the liability should be accreted to its face amount. The primary impact of this standard relates to oil and gas wells on which the Company has a legal obligation to plug and abandon the wells. The Company adopted SFAS No. 143 on January 1, 2003, that originally resulted in a cumulative effect adjustment of a $4.1 million increase in net income.

SFAS No. 143 requires the Company to make certain estimates, including estimates related to the future plugging costs of wells, the future salvage value of surface equipment, and estimated life of the Company's wells. In the fourth quarter of 2003, the Company made certain adjustments to its assumptions used in its initial SFAS No. 143 estimates to better reflect its future plugging costs and future salvage values. These changes resulted in a decrease in the cumulative effect adjustment from the $4.1 million originally reported during the quarter ended March 31, 2003, to $2.2 million. The following table details the amounts originally reported for the quarter ended March 31, 2003, compared to the current restated amount:

	Three Months Ended March 31, 2003	
(Dollars in thousands, except share data)	Originally Reported	Restated

Net income before change in accounting principle	$	5,342	$	5,342
Cumulative effect of change in accounting principle		4,090		2,162
Net income	$	9,432	$	7,504
Diluted earnings per share	$	0.66	$	0.52

The Company is an S-Corporation under Subchapter S of the Internal Revenue Code. As a result, income taxes, if any, will be payable by the stockholders of the Company. The Company operates principally in the following two segments:

1. Exploration and Production - The principal business of CRI and its wholly-owned subsidiary, Continental Resources of Illinois, Inc., or CRII, is oil and natural gas exploration, development and production. CRI and CRII have interests in approximately 2,207 wells and serve as the operator in the majority of these wells. CRI and CRII's operations are primarily in Illinois, Oklahoma, Wyoming, North Dakota, Texas, South Dakota, Montana, Kansas, Mississippi, Louisiana, Kentucky and Indiana.

At March 31, 2004, the Company had capitalized drilling and development costs of approximately $177.8 million related to the high-pressure air injection project currently in process in the Cedar Hills Field. Proved reserves associated with this field are approximately 42.2 MMBoe of which approximately 28.5 MMBoe, or 67%, are proved undeveloped. As of March 31, 2004, the Company had excluded $119.1 million, or 67%, of the development costs from the amortization base for purposes of computing depreciation, depletion and amortization, or DD&A. In future periods, the proved undeveloped reserves will be transferred to proved developed as such reserves meet the definition of proved reserves under SEC guidelines. Costs associated with the Cedar Hills Field will be added to the amortization base based on the ratio of proved developed reserves to proved undeveloped reserves. The Company's future DD&A rate on this field could be significantly impacted by upward or downward revisions in the oil and gas reserves associated with this field.

2. Gas Gathering, Marketing and Processing - Another wholly-owned subsidiary of CRI is Continental Gas, Inc., or CGI, which is engaged principally in natural gas marketing, gathering and processing activities and currently operates seven gas gathering systems and three gas processing plants in its operating areas. In addition, CGI participates with CRI in exploration, development and production of certain oil and natural gas properties.

2. LONG-TERM DEBT:

Long-term debt as of December 31, 2003, and March 31, 2004, consisted of the following:

(Dollars in thousands)		December 31, 2003		March 31, 2004
10.25% Senior Subordinated Notes due August 1, 2008	$	127,150	$	127,150
Credit Facility due March 31, 2007		132,900		140,400
Credit Facility due September 30, 2006		17,000		16,392
Capital Lease Agreement		13,827		12,993
Ford Credit		43		40
Outstanding Debt		290,920		296,975

Less Current Portion	5,776	5,776
Total Long-Term Debt	$ 285,144	$ 291,199

On March 31, 2002, the Company entered into a Fourth Amended and Restated Credit Agreement providing for a $175.0 million senior secured revolving credit facility with a borrowing base of $150.0 million. Borrowings under the credit facility are secured by liens on all oil and gas properties and associated assets of the Company. Borrowings under the credit facility bear interest, payable quarterly, at (a) a rate per annum equal to the rate at which eurodollar deposits for one, two, three or six months are offered by the lead bank plus a margin ranging from 150 to 250 basis points, or (b) at the lead bank's reference rate plus an applicable margin ranging from 25 to 50 basis points. At March 31, 2004, the lead bank's reference rate plus margins was 3.8%. The Company paid approximately $2.2 million in debt issuance fees for the credit facility, which have been capitalized as other assets and are being amortized on a straight-line basis over the life of the credit facility. The credit facility maturity date was extended on April 14, 2004, to March 31, 2007.

On October 22, 2003, the Company executed the Second Amendment to the Credit Agreement and CGI was removed as a guarantor of the Company's obligations under the Credit Agreement. The borrowing base under the Second Amendment to the Credit Agreement was revised to $145.0 million and $17.0 million funded by CGI as disclosed below reduced the outstanding balance.

On April 14, 2004, the company executed the Third Amendment to the Credit Agreement that provided for the addition of a term credit facility in an amount up to $25 million that matures on March 31, 2006. The amendment also extended the maturity date of the original facility to March 31, 2007, and increased the borrowing base to $150.0 million. Borrowings under the term credit facility have margins of 5.5% on LIBOR loans and 3% on prime loans. On April 14, 2004, the company drew $25 million on the new term credit facility and paid down the balance of the original revolving credit facility. At May 14, 2004, the outstanding balances were $124.5 million and $25.0 million on the original revolving credit facility and the term loan, respectively.

On October 22, 2003, CGI entered into a new $35.0 million secured credit facility consisting of a senior secured term loan facility of up to $25.0 million, and a senior revolving credit facility of up to $10.0 million. The initial advance under the term loan facility was $17.0 million, which CGI paid to CRI who used the payment to reduce the outstanding balance on CRI's credit facility. No funds were initially advanced under the revolving loan facility. Advances under either facility can be made, at the borrower's election, as reference rate loans or LIBOR loans and, with the respect to LIBOR loans, for interest periods of one, two, three, or six months. Interest is payable on reference rate loans monthly and on LIBOR loans at the end of the applicable interest period. The principal amount of the term loan facility is to be amortized on a quarterly basis through June 30, 2006, with the final payment due on September 30, 2006. The amount available under the revolving loan facility may be borrowed, repaid and reborrowed until maturity on September 30, 2006. Interest on reference rate loans is calculated with reference to a rate equal to the higher of the reference rate of Union Bank of California, N.A. or the federal funds rate plus 0.5%. Interest on LIBOR loans is calculated with reference to the London interbank offered interest rate. Interest accrues at the reference rate or the LIBOR rate, as applicable, plus the applicable margins. The margin is based on the then current senior debt to EBITDA ratio. The credit agreement contains certain covenants and requires certain quarterly mandatory prepayments on the term loan of 75% of excess cash flow. The credit facility is secured by a pledge of all the assets of CGI. At March 31, 2004, the outstanding balance on CGI's credit facility was $16.4 million.

CRI's credit agreement contains certain financial and other covenants. At March 31, 2004, CRI was not in compliance with two covenants, one that requires the Company to maintain a minimum current ratio of 1:1 and another that prohibits trading activity other than normal production contracts without prior approval of the required banks. On a pro-forma basis after giving effect to the Third Amendment to the Credit Agreement, the Company was in compliance with the current ratio covenant in its credit agreement. In May 2004 the Company requested and received from the bank group waivers for non-compliance with both covenants.

3. DERIVATIVE CONTRACTS:

The Company utilizes derivative contracts, consisting primarily of fixed price physical delivery contracts, including fixed price basis contracts, collars and floors to reduce its exposure to unfavorable changes in oil and gas prices that are subject to significant and often volatile fluctuation. Under fixed price physical delivery contracts, the Company receives the fixed price stated in the contract. Under the fixed price basis contracts, the price we receive is determined based on a published index price plus a fixed basis. Under collars and floors, if the market price of crude oil exceeds the ceiling strike price or falls below the floor strike price, then the Company receives the fixed price ceiling or floor. If the market price is between the floor strike price and the ceiling strike price, the Company receives market price.

The Company has designated its fixed price physical delivery contracts and fixed price basis contracts as "normal sales" contracts under SFAS No. 133, Accounting for Derivative and Hedging Activities and are therefore not marked to market as derivatives. The Company's collars and floors have been designated as and are being accounted for as cash flow hedges under SFAS No. 133. The following table summarizes the Company's fixed price physical delivery contracts, collars and floors in place at March 31, 2004:

	2004	2005	2006	2007
Natural Gas Physical Delivery Contracts:				
Contract Volumes (MMBtu)	450,000	600,000	600,000	600,000
Weighted Average Fixed Price per MMBtu	$ 4.83	$ 4.53	$ 4.47	$ 4.49

Crude Oil Basis Contracts:

Contract Month	Contract Volumes	Price
May 2004	184,000	$ 35.73
June 2004	90,000	$ 35.27
July 2004	62,000	$ 35.03

Crude Oil Collars and Floors for 2004:	Contract Volumes (Bbls)	Weighted-average Fixed Price per Bbl

Floor	926,000	$ 22.00
Floor	200,000	$ 24.00
Floor	230,000	$ 24.50
	1,356,000	
Ceiling	220,000	$ 35.00
Ceiling	515,000	$ 36.00
Ceiling	230,000	$ 45.00
	965,000	

The Company engages in a series of contracts in order to exchange its crude oil production in the Rocky Mountain area for equal quantities of crude oil located at Cushing, Oklahoma. Such activity enables the Company to take advantage of better pricing and reduce the Company's credit risk associated with its first purchaser. This purchase and sale activity is presented gross in the accompanying income statement as crude oil marketing revenues and expenses under the guidance provided by Emerging Issues Task Force Consensus 99-19, Reporting Revenues Gross as a Principal and Net as an Agent.

Additionally, in the first quarter of 2004, the Company engaged in certain crude oil trading activities, exclusive of its own production, utilizing fixed price and variable priced physical delivery contracts. For the three months ended March 31, 2004, crude oil marketing and trading revenues included $10.3 million and crude oil marketing and trading expenses also included $10.3 million, related to such trading activities. The Company had no crude oil trading activities in the first quarter of 2003. The Company's derivatives associated with this activity are being marked to market with all changes in fair value being recorded in the income statement under the accounting prescribed by SFAS No. 133, Accounting for Derivative and Hedging Activities. At March 31, 2004, the Company had the following open crude oil trading derivative contracts:

Contract Type	Contract Month	Weighted Average Fixed Price	Barrels Buy (Sell)	Unrealized Gain (Loss)
Crude Oil	April 2004	$ 34.84	(42,800)	$ (478,152)
Crude Oil	May 2004	35.56	(18,300)	(186,277)
Crude Oil	December 2004	31.41	30,000	268,200
			(31,100)	$ (396,229)

4. EARNINGS PER SHARE:

Basic earnings per common share is computed by dividing income available to common shareholders by the weighted-average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if stock options were exercised, using the treasury stock method of calculation. The weighted-average number of shares used to compute basic earnings per common share was 14,368,919 for the three months ended March 31, 2003 and 2004. The weighted-average number of shares used to compute diluted earnings per share was 14,463,210 for the three months ended March 31, 2003 and 2004.

5. GUARANTOR SUBSIDIARIES:

The Company's wholly owned subsidiaries, CGI, CRII, and Continental Crude Co. (CCC), have guaranteed the Company's obligations under its outstanding 10 1/4% Senior Subordinated Notes due 2008. CCC has not engaged in any business activities since its inception. The following is a summary of the condensed consolidating balance sheets of CGI and CRII as of December 31, 2003, and March 31, 2004, and the results of operations and cash flows for the three-month periods ended March 31, 2003, and 2004.

As of December 31, 2003 — Condensed Consolidating Balance Sheet

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminations	
Current Assets	$ 11,162	$ 44,428	$ (14,749)	$
Property and Equipment	58,826	380,606	0	
Other Assets	281	4,448	(14)	
Total Assets	$ 70,269	$ 429,482	$ (14,763)	$
Current Liabilities	$ 18,512	$ 44,694	$ (7,066)	$
Long-Term Debt	22,286	270,541	(7,683)	
Other Liabilities	4,943	21,829	0	
Stockholders' Equity	24,528	92,418	(14)	
Total Liabilities and Stockholders' Equity	$ 70,269	$ 429,482	$ (14,763)	$

As of March 31, 2004 — Condensed Consolidating Balance Sheet

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminations	
Current Assets	$ 9,882	$ 41,262	$ (13,664)	$
Property and Equipment	59,038	385,943	0	
Other Assets	263	4,103	(14)	
Total Assets	$ 69,183	$ 431,308	$ (13,678)	$
Current Liabilities	$ 13,688	$ 40,732	$ (3,278)	$
Long-Term Debt	24,378	277,207	(10,386)	
Other Liabilities	4,981	22,076	0	
Stockholders' Equity	26,136	91,293	(14)	
Total Liabilities and Stockholders' Equity	$ 69,183	$ 431,308	$ (13,678)	$

For the Three Months Ended March 31, 2003 — Condensed Consolidating Statements of Operat

($ in thousands) Guarantor

	Subsidiaries	Parent	Eliminations
Total Revenue	$ 15,845	$ 74,661	$ (2,279)
Operating Expense	(14,072)	(66,202)	2,279
Other Expense	(382)	(4,508)	0
Cumulative Effect of Change in Accounting Principle	(50)	2,212	0
Net Income	$ 1,341	$ 6,163	$ 0

For the Three Months Ended March 31, 2004 Condensed Consolidating Statements of Operat

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminations
Total Revenue	$ 24,350	$ 90,246	$ (5,185)
Operating Expense	(22,421)	(85,909)	5,185
Other Expense	(321)	(4,953)	0
Net Income	$ 1,608	$ (616)	$ 0

For the Three Months Ended March 31, 2003 Condensed Consolidated Cash Flows Statemen

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminations
Cash Flows From Operating Activities	$ 2,787	$ 33,502	$ (22,862)
Cash Flows From Investing Activities	(1,556)	(26,126)	-
Cash Flows From Financing Activities	(819)	18,719	-
Net Increase (Decrease) in Cash	412	26,095	(22,862)
Cash at Beginning of Period	456	2,064	-
Cash at End of Period	$ 868	$ 28,159	$ (22,862)

For the Three Months Ended March 31, 2004 Condensed Consolidated Cash Flow Statement

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminations
Cash Flow From Operating Activities	$ 4,598	$ 23,295	$ (13,664)
Cash Flow From Investing Activities	(1,819)	(18,693)	-
Cash Flow From Financing Activities	(617)	6,591	-
Net Increase (Decrease) in Cash	2,162	11,193	(13,664)
Cash at Beginning of Period	701	1,576	-
Cash at End of Period	$ 2,863	$ 12,769	$ (13,664)

6. BUSINESS SEGMENTS:

The Company has two reportable segments pursuant to Statement of Financial Accounting Standards (SFAS) No. 131, Disclosure About Segments of an Enterprise and Related Information, consisting of exploration and production, and gas gathering, marketing and processing. The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues from the exploration and production segment are derived from the production and sale of crude oil and natural gas. Revenues from the gas gathering, marketing and processing segment come from the transportation and sale of natural gas and natural gas liquids at retail. The accounting policies of the segments are the same. Financial information by operating segment is presented below:

For the Three Months Ended March 31, 2003 (Dollars in thousands)	Exploration and Production	Gas Gathering, Marketing and Processing	Intersegment
REVENUES:			
Oil and gas sales	$ 35,530	$ 192	$ -
Crude oil marketing and trading	40,595	-	-
Change in derivative fair value	303	-	-
Gas gathering, marketing and processing	-	12,004	(2,279)
Oil and gas service operations	1,882	-	-
Total revenues	$ 78,310	$ 12,196	$ (2,279)
OPERATING COSTS AND EXPENSES:			
Production expenses	8,581	50	-
Production taxes	2,659	15	-
Exploration	1,480	22	-
Crude oil marketing and trading	40,484	-	-
Gas gathering, marketing and processing	-	11,107	(2,279)
Oil and gas service operations	1,960	-	-
Depreciation, depletion and amortization:			
Oil and gas properties	8,549	(247)	-
Other property and equipment	525	623	-
Property impairments	1,273	3	-
Asset retirement accretion	350	2	-
General and administrative	2,683	155	-
Total operating costs and expenses	$ 68,544	$ 11,730	$ (2,279)
Total operating income	$ 9,766	$ 466	$ -
OTHER INCOME (EXPENSE):			
Interest income	90	2	(60)
Interest expense	(4,951)	(60)	60
Other income, net	37	-	
Loss on sale of assets	-	(8)	-
Total other income (expense)	$ (4,824)	$ (66)	$ -
Total income from operations	$ 4,942	$ 400	$ -
Cumulative effect of change in accounting principle	273	1,889	-
Net income	$ 5,215	$ 2,289	$ -

Total assets	$ 457,954	$ 33,258	$ (21,797)
Capital expenditures	$ 26,292	$ 1,446	$ -

For the Three Months Ended March 31, 2004 (Dollars in thousands)	Exploration and Production	Gas Gathering, Marketing and Processing	Intersegment
REVENUES:			
Oil and gas sales	$ 35,986	$ 137	$ -
Crude oil marketing and trading	55,705	-	-
Change in derivative fair value	(396)	-	-
Gas gathering, marketing and processing	-	21,050	(5,185)
Oil and gas service operations	2,114	-	-
Total revenues	$ 93,409	$ 21,187	$ (5,185)
OPERATING COSTS AND EXPENSES:			
Production expenses	10,479	69	-
Production taxes	2,570	12	-
Exploration	2,092	-	-
Crude oil marketing and trading	55,863	-	-
Gas gathering, marketing and processing	-	18,993	(5,185)
Oil and gas service operations	1,946	-	-
Depreciation, depletion and amortization:			
Oil and gas properties	10,445	22	-
Other property and equipment	348	817	-
Property impairments	1,897	-	-
Asset retirement accretion	273	4	-
General and administrative	2,222	278	-
Total operating costs and expenses	$ 88,135	$ 20,195	$ (5,185)
Total operating income	$ 5,274	$ 992	$ -
OTHER INCOME (EXPENSE):			
Interest income	25	2	-
Interest expense	(5,095)	(194)	-
Other income, net	12	11	
Loss on sale of assets	(35)	-	-
Total other income (expense)	$ (5,093)	$ (181)	$ -
Total income from operations	$ 181	$ 811	$ -
Net income	$ 181	$ 811	$ -
Total assets	$ 452,168	$ 48,322	$ (13,677)
Capital expenditures	$ 19,331	$ 1,359	$ -

7. COMPREHENSIVE INCOME (LOSS):

The components of total comprehensive income (loss) for the three months ended March 31, 2003 and 2004 are as follows:

(Dollars in thousands)	Three Months Ended March 31, 2003 (restated)	Three Months Ended March 31, 2004
Net Income	$ 7,504	$ 992
Other Comprehensive Income (Loss):		
Deferred Hedging Loss	-	(997)
Total Comprehensive Income (Loss)	$ 7,504	$ (5)

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

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements, and the notes thereto that appear elsewhere in this report, and our annual report on Form 10-K for the year ended December 31, 2003. Our operating results for the periods discussed may not be indicative of future performance. Statements concerning future results are forward-looking statements. In the text below, financial statement numbers have been rounded; however, the percentage changes are based on amounts that have not been rounded.

OVERVIEW

We foresee continued growth in 2004. Firm pricing coupled with anticipated increases in production this year look quite favorable for us. Our Cedar Hills North Unit and West Cedar Hills Unit are responding to high-pressure air injection, or HPAI, and to the water injections made throughout the previous 15 months. Response is occurring as initially simulated by our Resource Development group. Oil production in our Cedar Hills North Unit at March 31, 2004, was approximately 2,781 Bbls per day, an increase of 454 Bbls per day since November 2003, due to HPAI. Based on the current response and the anticipated continued response, we expect that approximately 4.0 million barrels of our reserves in our Cedar Hills North Unit will be moved from proved undeveloped (PUD) reserves to proved developed producing (PDP) reserves in mid-2004. We anticipate that an aggregate of up to 20.0 million barrels will be re-classified from PUD to PDP by the end of 2004. We expect our oil production in our Cedar Hills North Unit, on a daily basis, to double by the end of 2004 or in early 2005.

The following table reflects our production from our Cedar Hills Units beginning in November 2003, the time that we began to see HPAI response, through March 2004:

Property	Monthly Production (Bbls) Nov 2003	Monthly Production (Bbls) Mar 2004	Increase Bbls per Day

Cedar Hills North Unit	69,800	86,200	454
West Cedar Hills Unit	7,700	8,500	18
Total	77,500	94,700	472

Currently, our lifting costs in our Rocky Mountain Region are significantly higher than our historic average due to the energy costs and other associated costs used in HPAI recovery, coupled with the conversion of producing wells to injector wells to complete the injection pattern engineered for the field. Thus, less production is available at a time when injection costs are high. We expect our lifting costs per barrel to decline as response and increased production occurs. We expect a return to a normalized lifting cost per barrel in late 2004 or early 2005.

Our Middle Bakken well program currently is a 63 well drilling program in Richland County, Montana, that has been 100% successful. To date, we have drilled or participated in eight gross wells as part of this program, all of which are producing. We are currently drilling two wells. We anticipate drilling a total of 55 additional wells (including the two currently drilling), which we will operate in this area. We expect to commence 15 additional wells as part of this program in 2004. To date, 105 wells have been drilled by various operators in this area with no dry holes encountered. We expect our Middle Bakken wells to increase our proved reserve base by an average of 460,000 Bbls per well when completed.

We expect our offshore and Texas onshore wells, both operated and non-operated, will provide a balance of gas production for us. Our offshore group plans to set a platform this year based on a discovery well offshore Louisiana. We anticipate initial production from this area in late 2004 or early 2005.

During the first quarter of 2004, the plant throughput in our Matli gas-processing system was 1.4 Bcf, an increase of .6 Bcf, or 77% over the Matli plant throughput in the first quarter of 2003. In addition, during the first quarter of 2004 we drilled or participated in 16 wells of which 3 were unsuccessful. In the first quarter of 2003, we drilled or participated in 16 wells, all of which were successful.

Our capital expenditure budget for 2004 is $82.0 million. Through the end of the first quarter of 2004, our aggregate capital expenditures were $20.7 million.

THREE MONTHS ENDED MARCH 31, 2003, COMPARED TO THREE MONTHS ENDED MARCH 31, 2004

The following table shows our statement of operations for the first quarter of 2003 compared to the first quarter of 2004 with dollar and percentage increases or decreases:

REVENUES:	1st Quarter 2003	1st Quarter 2004	I (D
Oil and gas	$ 35,722	$ 36,123	$
Crude oil marketing and trading	40,595	55,705	
Change in derivative fair value	303	(396)	
Gas gathering, marketing and processing	9,725	15,865	
Oil and gas service operations	1,882	2,114	

Total revenues	$	88,227	$	109,411	$
OPERATING COSTS AND EXPENSES:					
Production	$	8,631	$	10,548	$
Production taxes		2,674		2,582	
Exploration		1,502		2,092	
Crude oil marketing and trading		40,484		55,863	
Gas gathering, marketing and processing		8,828		13,808	
Oil and gas service operations		1,960		1,946	
DD&A of oil and gas properties		8,302		10,467	
DD&A of other assets		1,148		1,165	
Property impairments		1,276		1,897	
Asset retirement obligation accretion		352		277	
General and administrative		2,838		2,500	
Total operating costs and expenses	$	77,995	$	103,145	$
OPERATING INCOME	$	10,232	$	6,266	$
OTHER INCOME AND EXPENSE:					
Interest income	$	32	$	27	$
Interest expense		(4,951)		(5,289)	
Other income, net		37		23	
Loss on sale of assets		(8)		(35)	
Total other income and (expenses)	$	(4,890)	$	(5,274)	$
INCOME BEFORE CHANGE IN ACCOUNTING PRINCIPLE	$	5,342	$	992	$
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$	2,162	$	-	$
NET INCOME	$	7,504	$	992	$

RESULTS OF OPERATIONS

The following table sets forth certain information regarding our production volumes, oil and gas sales, average sales prices and expenses for the periods indicated:

	For the Three Months Ended March 31, 2003	For the Three Months Ended March 31, 2004
NET PRODUCTION DATA:		
Oil and Condensate (MBbl)	907	787
Natural Gas (MMcf)	2,368	2,321
Total Oil equivalent (MBoe)	1,302	1,174
OIL AND GAS SALES (dollars in thousands)		
Oil sales, excluding hedges	$ 28,115	$ 25,450
Hedges	(4,726)	(454)
Total oil sales, including hedges	23,389	24,996
Gas sales	12,333	11,127

Total oil and gas sales	$ 35,722	$ 36,123
AVERAGE SALES PRICE:		
Oil, excluding hedges (dollar per barrel)	$ 31.01	$ 32.33
Oil, including hedges (dollar per barrel)	$ 25.78	$ 31.75
Gas (dollar per Mcf)	$ 5.21	$ 4.79
Oil equivalent, excluding hedges (dollar per Boe)	$ 31.07	$ 31.15
Oil equivalent, including hedges (dollar per Boe)	$ 27.44	$ 30.77
EXPENSES (dollar per Boe):		
Production expenses (including taxes)	$ 8.68	$ 11.18
General and administrative	$ 2.18	$ 2.13
DD&A (on oil and gas properties)	$ 6.38	$ 8.91

REVENUES

GENERAL

The increase in revenues is attributable to higher oil prices realized on our oil production and an increase in volumes from our oil marketing and trading programs. Gas gathering, marketing and processing revenues were higher for the three months ended March 31, 2004, compared to the same period in 2003 primarily due to our acquisition of the Carmen Gathering System, which increased our total throughput.

OIL AND GAS SALES

The decrease in oil and gas sales revenues was primarily attributable to a reduction in oil volumes due to the conversion of wells in our Cedar Hills North Unit to injection wells and certain of our oil and gas wells in Montana being shut in due to extreme weather during the first quarter of 2004.

The following table shows our production by region for the three months ended March 31, 2003 and 2004:

	Three Months Ended March 31,			
	2003		2004	
	MBoe	Percent	MBoe	Percent
Rocky Mountain	772	59.29%	681	58.01%
Mid-Continent	391	30.03%	369	31.43%
Gulf	139	10.68%	124	10.56%
	1,302	100.00%	1,174	100.00%

CRUDE OIL MARKETING AND TRADING

We enter into a series of contracts in order to exchange our crude oil production in our Rocky Mountain Region for equal quantities of crude oil located at Cushing, Oklahoma. Through this activity, we take advantage of better pricing and reduce our credit risk associated with our first purchaser. In our income statement, we present this purchase and sale activity separately as crude oil marketing revenues and crude oil marketing expenses, based on guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and or Net as an Agent.

Additionally, in the first quarter of 2004, we engaged in certain crude oil trading activities, exclusive of our own production, utilizing fixed price and variable priced physical delivery contracts. For the three months ended March 31, 2004, crude oil marketing revenues were $10.3 million and crude oil marketing expenses were also $10.3 million, related to such trading activities. We had no crude oil marketing revenue or expense in the first quarter of 2003. Our derivative trading activities are being marked to market with all changes in fair value being recorded in the income statement under the accounting prescribed by SFAS No. 133, Accounting for Derivative and Hedging Activities.

CHANGE IN DERIVATIVE FAIR VALUE

The change in derivative fair value for the three months ended March 31, 2003, related to a crude oil derivative contract used to reduce our exposure to changes in crude oil prices but did not qualify for special hedge accounting under SFAS No. 133. Such contract expired at December 31, 2003. The change in derivative fair value for the three months ended March 31, 2004, is the result of those derivative trading contracts described in Note 3 to our Condensed Consolidated Financial Statements.

GAS GATHERING, MARKETING AND PROCESSING

The increase in our gas gathering, marketing and processing revenue during the first quarter of 2004 was attributable to increased throughput volumes resulting from growth in our existing systems and our acquisition of the Carmen Gathering System in July 2003.

OIL AND GAS SERVICE OPERATIONS

The increase in our oil and gas service operations was primarily due to an increase in reclaimed oil revenue of $0.3 million due to higher oil prices, offset by decreases in our other income of $0.1 million.

COSTS AND EXPENSES

PRODUCTION EXPENSES AND TAXES

Our production expenses including taxes increased primarily due to increased energy expense of $1.0 million. Energy expense increased due to higher utility costs in general and costs associated with running the compressors for HPAI in the Cedar Hills Units. Our labor costs increased $0.3 million in the first quarter of 2004 compared to the first quarter of 2003.

EXPLORATION EXPENSES

The increase in exploration expense was primarily due to an increase in our dry hole costs of $1.2 million in the Gulf Coast region, partially offset by decreases in other expenses of $0.6 million.

CRUDE OIL MARKETING AND TRADING

The increase in our crude oil marketing expense was primarily due to increased prices for oil that we purchased and increased volumes marketed and traded.

GAS GATHERING, MARKETING, AND PROCESSING

The increase in our gas gathering, marketing and processing expense during the first quarter of 2004 was attributable to increased throughput volumes resulting from growth in our existing systems and our acquisition of the Carmen Gathering System in July 2003.

OIL AND GAS SERVICE OPERATIONS

The change in our oil and gas service operations expense was immaterial.

DEPRECIATION, DEPLETION AND AMORTIZATION OF OIL AND GAS PROPERTIES (DD&A)

Depletion increased $2.3 million in the first quarter of 2004 compared to the first quarter of 2003, due to certain developmental dry hole costs being added to our amortization base and depleted with the costs of the related field and due to higher production decline rates in our Gulf Coast Region. The decline rate on one of our more significant fields in the Gulf Coast Region increased from 14% to 40% due principally to the rapid depletion of the reserves in this field. In the first quarter of 2004, our DD&A expense on our oil and gas properties was calculated at $8.91 per BOE, compared to $6.38 per BOE for the first quarter of 2003.

DEPRECIATION AND AMORTIZATION OF OTHER PROPERTY AND EQUIPMENT

Our change in depreciation and amortization expense related to our other property and equipment was immaterial.

PROPERTY IMPAIRMENTS

The increase in our property impairments was primarily due to increased impairment on capitalized costs of our undeveloped leasehold.

ASSET RETIREMENT ACCRETION

We adopted SFAS No. 143, Accounting for Asset Retirement Obligations, on January 1, 2003. For the three months ended March 31, 2004, our asset retirement accretion was $0.3 million compared to $0.4 million for the comparable period in 2003.

GENERAL AND ADMINISTRATIVE (G&A)

Our G&A expense per BOE for the first quarter of 2004 was $2.13 compared to $2.18 for the first quarter of 2003.

INTEREST EXPENSE

The increase in our interest expense was due to additional interest on higher average debt balances outstanding under our credit facilities during the first quarter of 2004.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOW FROM OPERATIONS

Net cash provided by our operating activities for the three months ended March 31, 2004, was $14.2 million, an increase of $0.8 million from $13.4 million provided by our operating activities during the comparable 2003 period. Our cash balance as of March 31, 2004, was $2.0 million, a decrease of $0.3 million from our cash balance of $2.3 million held at December 31, 2003.

DEBT

Our long-term debt at December 31, 2003, was $285.1 million and at March

31, 2004, $291.2 million. At March 31, 2004, we had outstanding $127.2 million principal amount in our senior subordinated notes, $156.8 million outstanding under our secured credit facilities, and $7.2 million outstanding in capital lease obligations with $5.8 million due within the next year.

CREDIT FACILITY

At March 31, 2004, we had $140.4 million of revolving credit debt outstanding under our exploration and production secured credit facility. Borrowings under our credit facility bear interest based on an annual rate equal to the rate at which eurodollar deposits for one, two, three or six months are offered by the lead bank plus an applicable margin ranging from 150 to 250 basis points or the lead bank's reference rate plus an applicable margin ranging from 25 to 50 basis points. The effective rate of interest on our borrowings under our credit facility was 3.8% at March 31, 2004. The borrowing base of our credit facility was $145.0 million on March 31, 2004 and is re-determined semi-annually. Borrowings under our exploration and production credit facility are secured by liens on substantially all of our assets.

On April 14, 2004, the company executed the Third Amendment to the Credit Agreement that provided for the addition of a term credit facility in an amount up to $25 million that matures on March 31, 2006. The amendment also extended the maturity date of the original facility to March 31, 2007, and increased the borrowing base to $150.0 million. Borrowings under the term credit facility have margins of 5.5% on LIBOR loans and 3% on prime loans. On April 14, 2004, the company drew $25 million on the new term credit facility and paid down the balance of the original revolving credit facility. At May 6, 2004, the outstanding balances were $124.5 million and $25.0 million on the original revolving credit facility and the term loan, respectively.

On October 22, 2003, our subsidiary, Continental Gas, Inc, or CGI, established a new $35.0 million secured credit facility consisting of a senior secured term loan facility of up to $25.0 million and a senior revolving credit facility of up to $10.0 million. On that date, CGI ceased to be a guarantor of our obligations under our credit agreement. The initial advance under the term loan facility was $17.0 million, which was paid to CRI and used to reduce the outstanding balance on our credit facility. No funds were initially advanced under the revolving loan facility. Advances under either facility can be made, at the borrower's election, as reference rate loans or LIBOR rate loans and, with respect to LIBOR loans, for interest periods of one, two, three, or six months. Interest is payable on reference rate loans monthly and on LIBOR loans at the end of the applicable interest period. The principal amount of the term loan facility is to be amortized on a quarterly basis through June 30, 2006, the final payment being due September 30, 2006. The amount available under the revolving loan facility may be borrowed, repaid and reborrowed until maturity on September 30, 2006. Interest on reference rate loans is calculated at a rate equal to the higher of the reference rate of Union Bank of California, N.A. or the federal funds rate plus 0.5%. Interest on LIBOR loans is calculated with reference to the London Interbank Offered rate. Interest accrues at the reference rate or the LIBOR rate, as applicable, plus the applicable margin. The margin is based on the ratio of senior debt to EBITDA. The credit agreement contains certain covenants and requires certain quarterly mandatory prepayments of 75% of excess cash flow. The credit facility is secured by a pledge of all of the assets of CGI. At March 31, 2004 the outstanding balance on CGI's credit facility was $16.4 million.

Our credit agreement contains certain financial and other covenants. At March 31, 2004, we were not in compliance with two covenants, one that requires us to maintain a minimum current ratio of 1:1 and another that prohibits trading activity other than normal production contracts without prior approval of the required banks. On a pro-forma basis after giving effect to the Third Amendment to the Credit Agreement, we were in compliance with the current ratio covenant in our credit agreement. In May 2004, we requested and received from the bank group a waiver for non-compliance of both covenants as of March 31, 2004. In the future, we will seek prior approval on our trading activities from the required banks.

CAPITAL EXPENDITURES

Our 2004 capital expenditures budget, exclusive of acquisitions, is $82.0 million, of which $6.7 million is dedicated to our Cedar Hills Field secondary recovery project. During the three months ended March 31, 2004, we incurred $20.7 million of capital expenditures, compared to $27.7 million during the three-month period of 2003. Of the total $20.7 million of capital expenditures, we expended $15.0 in exploration and development, and $3.5 million on secondary recovery operations. We used the remaining $2.2 million for leasing and additions to our gas gathering systems. The $7.0 million decrease in our capital expenditures during the first quarter of 2004 compared to the first quarter of 2003 was the result of our near completion of the high-pressure air injection project in the Cedar Hills Field in our Rocky Mountain Region. We expect to fund the remainder of our 2004 capital budget through cash flows from operations and borrowings under our credit facility.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements". All statements other than statements of historical fact, including, without limitation, statements contained under "Management's Discussion and Analysis of Financial Condition and Results of Operations" regarding our financial position, business strategy, plans and objectives of our management for future operations and industry conditions, are forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to be correct. Important factors that could cause actual results to differ materially from our expectations ("Cautionary Statements") include, without limitation, future production levels, future prices and demand for oil and gas, results of future exploration and development activities, future operating and development costs, the effect of existing and future laws and governmental regulations (including those pertaining to the environment) and the political and economic climate of the United States as discussed in this quarterly report and the other documents we previously filed with the Securities and Exchange Commission. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the Cautionary Statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

GENERAL

We are exposed to market risks, including commodity price risk and interest rate risk, in the normal course or our business operations. Information regarding our exposures to these market risks is provided below.

COMMODITY PRICE EXPOSURE

Non-trading

We utilize fixed-price contracts, including fixed price basis contracts, collars and floors to reduce exposure to the unfavorable changes in oil and gas prices that are subject to significant and often volatile fluctuation. Under the fixed price physical delivery contracts we receive the fixed price stated in the contract. Under the fixed price basis contracts, the price we receive is determined based on a published regional index price plus a fixed basis. Under the collars and floors, if the market price of crude oil exceeds the ceiling strike price or falls below the floor strike price, then we receive the fixed price ceiling or floor. If the market price is between the floor strike price and the ceiling strike price, we receive market price.

These contracts allow us to predict with greater certainty the effective oil and gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, we will not benefit from market prices that are higher than the fixed, or ceiling prices in the contracts for hedged production.

The terms of our credit facility require that at least 50% of our forecasted crude oil production from our exploration and production segment be hedged on a rolling six-month term. At March 31, 2004, we had collars and/or floors in place covering approximately 1.4 million barrels of crude oil representing approximately 66% of our forecasted production through September 30, 2004. At March 31, 2004, we had a mark-to-market unrealized loss of approximately $996,600 on our collar and floor contracts. As such contracts have been designated and qualify as cash flow hedges, the loss has been recorded as a component of Accumulated Other Comprehensive Income at March 31, 2004. The ineffectiveness associated with our cash flow hedging strategy was immaterial.

Additionally, CGI has executed fixed price forward sales contracts related to our gas gathering, marketing and processing segment on approximately 50,000 MMBtu per month through December 2007. Such contracts have been designated as normal sales under SFAS No. 133 and are therefore not marked to market as derivatives. These volumes under these fixed price forward sales contracts represent approximately 9% of total delivery point volumes and 4% of the overall throughput volumes of the gas gathering, marketing and processing segment.

The following table summarizes our non-trading contracts in place at March 31, 2004:

	2004	2005	2006	2007
Natural Gas Physical Delivery Contracts:				
Contract Volumes (MMBtu)	450,000	600,000	600,000	600,000
Weighted Average Fixed Price per MMBtu	$ 4.83	$ 4.53	$ 4.47	$ 4.49

Crude Oil Collars and Floors for 2004:	Contract Volumes (Bbls)	Weighted-average Fixed Price per Bbl
Floor	926,000	$ 22.00
Floor	200,000	$ 24.00
Floor	230,000	$ 24.50
	1,356,000	
Ceiling	220,000	$ 35.00
Ceiling	515,000	$ 36.00
Ceiling	230,000	$ 45.00
	965,000	

The following table represents our fixed basis contracts in place at March 31, 2004. The price shown below represents the price we would have received based on the current forward crude oil price for the applicable month combined with the fixed basis differential contained in the contract.

Contract Month	Contract Volumes	Price
May 2004	184,000	$ 35.73
June 2004	90,000	$ 35.27
July 2004	62,000	$ 35.03

Trading

In the first quarter of 2004, we engaged in certain crude oil trading activities, exclusive of our own production, utilizing fixed price and variable price physical delivery contracts. At March 31, 2004, we had the following open trading derivative contracts:

Contract Type	Contract Month	Weighted Average Fixed Price	Barrels Buy (Sell)	Unrealized Gain (Loss)
Crude Oil	April 2004	$ 34.84	(42,800)	$ (478,152)
Crude Oil	May 2004	35.56	(18,300)	(186,277)
Crude Oil	December 2004	31.41	30,000	268,200
			(31,100)	$ (396,229)

INTEREST RATE RISK

Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. The fair value of long-term debt is estimated based on quoted market prices and management's estimate of current rates available for similar issues. The following table itemizes our long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in thousands)	2004	2005	2006	2007	Thereafter	Total
Fixed rate debt:						
Senior subordinated notes						

Principal amount	$ -	$ -	$ -	$ -	$ 127,150	$ 127,15
Weighted-average interest rate	10.25%	10.25%	10.25%	10.25%	10.25%	
Variable rate debt:						
Credit facility						
Principal amount	$ 1,821	$ 2,430	$ 12,141	$ 140,400	$ -	$ 156,79
Weighted-average interest rate	3.80%	3.80%	3.80%	3.80%	3.80%	
Variable rate debt:						
Capital lease agreement						
Principal amount	$ 2,502	$ 3,336	$ 3,336	$ 3,333	$ 486	$ 12,99
Weighted-average interest rate	3.80%	3.80%	3.80%	3.80%	3.80%	
Variable rate debt:						
Ford Credit agreement						
Principal amount	$ 8	$ 13	$ 11	$ 8	$ -	$ 4
Weighted-average interest rate	5.50%	5.50%	5.50%	5.50%	5.50%	

ITEM 4. CONTROLS AND PROCEDURES

The Securities and Exchange Commission rules require registrants to maintain disclosure controls and procedures to provide reasonable assurance that a registrant is able to record, process, summarize and report the information required in the registrant's quarterly and annual reports under the Securities Exchange Act of 1934. While we believe that our existing disclosure controls and procedures have been effective to accomplish these objectives, we intend to continue to examine, refine and formalize our disclosure controls and procedures and to maintain ongoing developments in this area.

As of the end of the period covered by this report, our principal executive officer and principal financial officer have evaluated our disclosure controls and procedures (as defined in Rule 13a-14(c) under the Securities Exchange Act of 1934) and concluded that our disclosure controls and procedures are effective.

There have been no significant changes in our internal controls or in other factors that could significantly affect these controls, since the date the controls were evaluated.

PART II. Other Information

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. We are not involved in any legal proceedings nor are we a party to any pending or threatened claims that could reasonably be expected to have a material adverse effect on our financial condition or results of operations.

ITEM 2. CHANGES IN SECURITIES, USE OF PROCEEDS AND ISSUER PURCHASES OF EQUITY SECURITIES

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

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

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) EXHIBITS:

EXHIBIT NO.		DESCRIPTION AND METHOD OF FILING:
3.1		Amended and Restated Certificate of Incorporation of Continental Resources, Inc. [3.1](1)
3.2		Amended and Restated Bylaws of Continental Resources, Inc. [3.2](1)
4.1		Fourth Amended and Restated Credit Agreement dated March 28, 2002, among the Registrant, Union Bank of California, N.A., Guaranty Bank, FSB and Fortis Capital Corp. [10.1](5)
4.1.1		First Amendment to the Revolving Credit Agreement dated June 12, 2003, among the Registrant, Union Bank of California, N.A., Guaranty Bank, FSB and Fortis Capital Corp. [10.1](6) 4.1.2 Second Amendment to the Revolving Credit Agreement dated October 22, 2003, among the Registrant, Union Bank of California, N.A., Guaranty Bank, FSB and Fortis Capital Corp. [10.1](7)
4.1.3	*	Third Amendment to the Revolving Credit Agreement dated April 14, 2004, among the Registrant, Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., and The Royal Bank of Scotland plc.
4.2		Indenture dated as of July 24, 1998, between Continental Resources, Inc. as Issuer, the Subsidiary Guarantors named therein and the United States Trust Company of New York, as Trustee. [4.2](1)
10.1		Unlimited Guaranty Agreement dated March 28, 2002. [10.2](5)
10.2		Security Agreement dated March 28, 2002, between Registrant and Guaranty Bank, FSB, as Agent. [10.3](5)
10.3		Stock Pledge Agreement dated March 28, 2002, between Registrant and Guaranty Bank, FSB, as Agent. [10.4](5)
10.4	+	Continental Resources, Inc. 2000 Stock Option Plan. [10.6](2)
10.5	+	Form of Incentive Stock Option Agreement. [10.7](2)
10.6	+	Form of Non-Qualified Stock Option Agreement. [10.8](2)
10.7		Collateral Assignment of Contracts dated March 28, 2002, between Registrant and Guaranty Bank, FSB, as Agent. [10.5](5)
12.1	*	Statement re computation of ratio of debt to Adjusted EBITDA.

12.2 * Statement re computation of ratio of earning to fixed charges.

31.1 * Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002 - Chief Executive Officer

31.2 * Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002 - Chief Financial Officer

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* Filed herewith

\+ Represents management compensatory plans or agreements

(1) Filed as an exhibit to the Company's Registration Statement on Form S-4, as amended (No. 333-61547), which was filed with the Securities and Exchange Commission. The exhibit number is indicated in brackets and is incorporated herein by reference.

(2) Filed as an exhibit to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2000. The exhibit number is indicated in brackets and is incorporated herein by reference.

(3) Filed as an exhibit to the Company's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2001. The exhibit number is indicated in brackets and is incorporated herein by reference.

(4) Filed as an exhibit to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2001. The exhibit number is indicated in brackets and is incorporated herein by reference.

(5) Filed as an exhibit to current report on Form 8-K dated April 11, 2002. The exhibit number is indicated in brackets and is incorporated herein by reference.

(6) Filed as an exhibit to the Company's Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2003. The exhibit number is indicated in brackets and is incorporated herein by reference.

(7) Filed as an exhibit to current report on Form 8-K dated October 22, 2003. The exhibit number is indicated in brackets and is incorporated herein by reference.

(8) Filed as an exhibit to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2003. The exhibit number is indicated in brackets and is incorporated herein by reference.

(9) Filed as an exhibit to the Company's Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2004. The exhibit number is indicated in brackets and is incorporated herein by reference.

(b) REPORTS ON FORM 8-K:

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Continental Resources, Inc.

Date: May 13, 2004

By: ROGER V. CLEMENT
Roger V. Clement
Senior Vice President and
Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Description	Method of Filing
3.1	Amended and Restated Certificate of Incorporation of Continental Resources, Inc.	Incorporated by reference
3.2	Amended and Restated Bylaws of Continental Resources, Inc.	Incorporated by reference
4.1	Fourth Amended and Restated Credit Agreement dated March 28, 2002, among the Registrant, Union Bank of California, N.A., Guaranty Bank, FSB and Fortis Capital Corp.	Incorporated by reference
4.1.1	First Amendment to the Revolving Credit Agreement dated June 12, 2003, among the Registrant, Union Bank of California, N.A., Guaranty Bank, FSB and Fortis Capital Corp. [10.1](6)	Incorporated by reference
4.1.2	Second Amendment to the Revolving Credit Agreement dated October 22, 2003, among the Registrant, Union Bank of California, N.A., Guaranty Bank, FSB and Fortis Capital Corp.	Incorporated by reference
4.1.3	Third Amendment to the Revolving Credit Agreement dated April 14, 2004, among the Registrant, Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., and The Royal Bank of Scotland plc.	Filed herewith electronically
4.2	Indenture dated as of July 24, 1998, between Continental Resources, Inc. as Issuer, the Subsidiary Guarantors named therein and the United States Trust Company of New York, as Trustee.	Incorporated by reference
10.1	Unlimited Guaranty Agreement dated March 28, 2002.	Incorporated by reference
10.2	Security Agreement dated March 28, 2002, between Registrant and	Incorporated by reference

	Guaranty Bank, FSB, as Agent.	
10.3	Stock Pledge Agreement dated March 28, 2002, between Registrant and Guaranty Bank, FSB, as Agent.	Incorporated by reference
10.4	Continental Resources, Inc. 2000 Stock Option Plan.	Incorporated by reference
10.5	Form of Incentive Stock Option Agreement.	Incorporated by reference
10.6	Form of Non-Qualified Stock Option Agreement.	Incorporated by reference
10.7	Collateral Assignment of Contracts dated March 28, 2002, between Registrant and Guaranty Bank, FSB, as Agent.	Incorporated by reference
12.1	Statement re computation of ratio of debt to Adjusted EBITDA.	Filed herewith electronically
12.2	Statement re computation of ratio of earning to fixed charges.	Filed herewith electronically
31.1	Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002 - Chief Executive Officer	Filed herewith electronically
31.2	Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002 - Chief Financial Officer	Filed herewith electronically