CONTINENTAL RESOURCES INC
Form 10-Q
August 16, 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 June 30, 2004

OR

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

Commission File Number: 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 1500, 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 August 13, 2004
Common Stock, $.01 par value	14,368,919 shares

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PART I. Financial Information

PART I. Financial Information

ITEM 1. FINANCIAL STATEMENTS

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

Assets	December 31, 2003	June 30,
		(Unaud
Current assets:		
Cash and cash equivalents	$ 2,277	$
Accounts receivable:		
Oil and gas sales	19,035	
Joint interest and other, net	13,577	
Inventories	5,465	
Prepaid expenses	336	
Fair value of derivative contracts	151	
Total current assets	40,841	
Property and equipment, at cost:		
Oil and gas properties, based on successful efforts accounting	601,325	
Gas gathering and processing facilities	49,600	
Service properties, equipment and other	19,515	
Total property and equipment	670,440	
Less accumulated depreciation, depletion and amortization	231,008	

Net property and equipment	439,432	
Other assets:		
Debt issuance costs, net	4,707	
Other assets	8	
Total other assets	4,715	
Total assets	$ 484,988	$
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable	$ 27,950	$
Current portion of long-term debt	5,776	
Revenues and royalties payable	8,250	
Accrued liabilities:		
Interest	6,312	
Other	7,212	
Fair value of derivative contracts	640	
Total current liabilities	56,140	
Long-term debt, net of current portion	285,144	
Asset retirement obligation	26,608	
Other noncurrent liabilities	164	
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	
Additional paid-in-capital	25,087	
Retained earnings	92,190	
Accumulated other comprehensive income	(489)	
Total stockholders' equity	116,932	
Total liabilities and stockholders' equity	$ 484,988	$

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 End
	2003
Revenues:	(restated)
Oil and gas sales	$ 33,347
Crude oil marketing and trading	39,753
Change in derivative fair value	104

Gas gathering, marketing and processing	17,125
Oil and gas service operations	2,423
Total revenues	92,752
Operating costs and expenses:	
Production	10,342
Production taxes	2,361
Exploration	2,551
Crude oil marketing and trading	39,392
Gas gathering, marketing and processing	15,793
Oil and gas service operations	1,341
Depreciation, depletion and amortization of oil and gas properties	6,914
Depreciation and amortization of other property and equipment	1,231
Property impairments	1,276
Asset retirement obligation accretion	358
General and administrative	2,698
Total operating costs and expenses	84,257
Operating income	8,495
Other income (expense):	
Interest income	28
Interest expense	(4,964)
Other income, net	13
Gain (loss) on disposition of assets	277
Total other income (expense)	(4,646)
Net income	$ 3,849
Basic earnings per common share	$ 0.27
Diluted earnings per common share	$ 0.27

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)

	Six Months Ended Ju
	2003
Revenues:	(restated)
Oil and gas sales	$ 69,069
Crude oil marketing and trading	80,348
Change in derivative fair value	407
Gas gathering, marketing and processing	26,850
Oil and gas service operations	4,305

Total revenues	180,979	
Operating costs and expenses:		
Production	19,755	
Production taxes	5,035	
Exploration	4,053	
Crude oil marketing and trading	79,876	
Gas gathering, marketing and processing	24,621	
Oil and gas service operations	2,732	
Depreciation, depletion and amortization of oil and gas properties	15,217	
Depreciation and amortization of other property and equipment	2,379	
Property impairments	2,552	
Asset retirement obligation accretion	709	
General and administrative	5,323	
Total operating costs and expenses	162,252	
Operating income	18,727	
Other income (expense):		
Interest income	59	
Interest expense	(9,916)	
Other income, net	50	
Gain (loss) on disposition of assets	270	
Total other income (expense)	(9,537)	
Income before change in accounting principle	9,190	
Cumulative effect of change in accounting principle	2,162	
Net income	$ 11,352	$
Basic earnings per common share:		
Earnings before cumulative effect of accounting change	$ 0.64	$
Cumulative effect of accounting change	0.15	
Basic	$ 0.79	$
Diluted earnings per common share:		
Earnings before cumulative effect of accounting change	$ 0.64	$
Cumulative effect of accounting change	0.15	
Diluted	$ 0.79	$

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)

Six Months Ended June 30,

	2003	2004
Cash flows from operating activities:	(restated)	
Net income	$ 11,352	$ 7,9
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion and amortization	17,596	22,5
Accretion of asset retirement obligation	709	5
Impairment of properties	2,552	3,6
Change in derivative fair value	(407)	(4
Amortization of debt issuance costs	791	8
(Gain) loss on disposition of assets	(450)	1
Change in accounting principle	(2,162)	
Dry hole costs	2,775	3,9
Cash provided by (used in) changes in assets and liabilities-		
Accounts receivable	(2,401)	(2,3
Inventories	(1,143)	6
Prepaid expenses	154	
Accounts payable	(2,623)	(6,0
Revenues and royalties payable	149	1,5
Accrued liabilities and other	828	(1,4
Other noncurrent liabilities	23	
Net cash provided by operating activities	27,743	31,5
Cash flows from investing activities:		
Exploration and development	(49,922)	(37,5
Gas gathering and processing facilities and service properties, equipment and other	(2,806)	(4,0
Purchase of oil and gas properties	(83)	(3
Proceeds from disposition of assets	4,482	1
Net cash used in investing activities	(48,329)	(41,7
Cash flows from financing activities:		
Proceeds from line of credit and other debt	23,000	20,1
Repayment of debt	(1,200)	(2,8
Debt issuance costs	(75)	(1,5
Net cash provided by financing activities	21,725	15,6
Net increase in cash	1,139	5,5
Cash and cash equivalents, beginning of year	2,520	2,2
Cash and cash equivalents, end of period	$ 3,659	$ 7,8

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 management 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 June 30, 2004, and the results of operations and cash flows for the three months ended June 30, 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. Certain reclassifications have been made to prior year amounts to conform to the current year presentation.

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 six months ended June 30, 2003, compared to the current restated amount:

	Six Months Ended June 30, 2003	
(Dollars in thousands, except share data)	Originally Reported	Restated
Net income before change in accounting principle	$ 9,190	$ 9,190
Cumulative effect of change in accounting principle	4,090	2,162
Net income	$ 13,280	$ 11,352
Diluted earnings per share	$ 0.92	$ 0.79

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 June 30, 2004, the Company had capitalized drilling and development costs of approximately $180.4 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 41.9 MMBoe of which approximately 18.9 MMBoe, or 45%, are proved developed non-producing, or PDNP. In future periods, the PDNP reserves will be transferred to PDP as such reserves meet the definition of proved reserves under SEC guidelines 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. In July 2004, but effective May 31, 2004, CRI sold all of the outstanding capital stock of CGI to the shareholders of CRI. (See Note 8.)

2. LONG-TERM DEBT:

Long-term debt as of December 31, 2003, and June 30 2004, consisted of the following:

(Dollars in thousands)	December 31, 2003	June 30, 2004
10.25% Senior Subordinated Notes due August 1, 2008	$ 127,150	$ 127,150
Credit Facility due March 31, 2007	132,900	128,049
Credit Facility due March 31, 2006	-	25,000
Credit Facility due September 30, 2006	17,000	15,786
Capital Lease Agreement	13,827	12,159
Ford Credit	43	36
Outstanding Debt	290,920	308,180
Less Current Portion	5,776	5,776
Total Long-Term Debt	$ 285,144	$ 302,404

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 June 30, 2004, the lead bank's reference rate plus margins was 4.2%. 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 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 August 13, 2004, the outstanding balances were $137.0 million and $25.0 million on the original revolving credit facility and the term loan, respectively.

On July 21, 2004, the Company executed the Fourth Amendment to the Credit Agreement that modified the definitions to delete any reference to CGI. (See Note 8.)

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 June 30, 2004, the outstanding balance on CGI's credit facility was $15.8 million.

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 the Company receives is determined based on a published index price plus or minus 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 cash flow hedges under SFAS No. 133 and are being accounted for accordingly. The following table summarizes the Company's fixed price physical delivery contracts, collars and floors in place at June 30, 2004:

	2004	2005	2006	2007
Natural Gas Physical Delivery Contracts:				
Contract Volumes (MMBtu)	300,000	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
	Aug 2004	62,000	$ 37.72
	Sep 2004	30,000	$ 41.09

Crude Oil Collars and Floors for 2004:	Contract Volumes (Bbls)	Weighted-average Fixed Price per Bbl
July - Oct, Floor	602,000	$ 22.00
Sept - Oct, Floor	200,000	$ 24.00
Nov - Dec, Floor	230,000	$ 24.50
	1,032,000	
July - Oct, Ceiling	460,000	$ 36.00
Nov - Dec, Ceiling	230,000	$ 45.00
	690,000	

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 June 30, 2004, crude oil marketing and trading revenues included $9.9 million offset by crude oil marketing and trading expenses of $10.1 million, related to such trading activities. 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 June 30, 2004, the Company had closed its open trading positions, locking in an unrealized gain of $404,100 on such contracts.

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 and six months ended June 30, 2003 and 2004. The weighted-average number of shares used to compute diluted earnings per share was 14,463,210 for the three and six months ended June 30, 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 August 1, 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 June 30, 2004, and the results of operations and cash flows for the three-month and six-month periods ended June 30, 2003, and 2004.

As of December 31, 2003 — Condensed Consolidating Ba

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

As of June 30, 2004 — Condensed Consolidating Ba

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminati

Current Assets	$ 12,850	$ 49,323	$ (13,
Property and Equipment	59,952	390,905	
Other Assets	236	5,172	
Total Assets	$ 73,038	$ 445,400	$ (13,
Current Liabilities	$ 16,305	$ 37,501	$ (3,
Long-Term Debt	23,590	289,022	(10,
Other Liabilities	5,065	22,207	
Stockholders' Equity	28,078	96,670	
Total Liabilities and Stockholders' Equity	$ 73,038	$ 445,400	$ (13,

For the Three Months Ended June 30, 2003 Condensed Consolidating In

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminati
Total Revenue	$ 19,581	$ 72,401	$
Operating Expense	(18,382)	(65,105)	(
Other Expense	(302)	(4,344)	
Net Income	$ 897	2,952	$

For the Three Months Ended June 30, 2004 Condensed Consolidating In

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminati
Total Revenue	$ 27,576	$ 96,395	$ (4,
Operating Expense	(25,319)	(86,200)	4,
Other Expense	(315)	(5,169)	
Net Income	$ 1,942	$ 5,026	$

For the Six Months Ended June 30, 2003 Condensed Consolidating In

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminati
Total Revenue	$ 35,426	$ 147,062	$ (1,
Operating Expense	(32,454)	(131,307)	1,
Other Expense	(685)	(8,852)	
Cumulative Effect of Change in Accounting Principle	(50)	2,212	
Net Income	$ 2,237	$ 9,115	$

For the Six Months Ended June 30, 2004 Condensed Consolidating In

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminati
Total Revenue	$ 51,926	$ 186,641	$ (9,

Operating Expense	(47,741)	(172,109)	9,
Other Expense	(635)	(10,123)	
Net Income	$ 3,550	$ 4,409	$

For the Six Months Ended June 30, 2003 — Condensed Consolidated Cas

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminati
Cash Flows From Operating Activities	$ 4,268	$ 23,531	$
Cash Flows From Investing Activities	(5,035)	(43,294)	
Cash Flows From Financing Activities	(1,724)	21,725	1,
Net Increase (Decrease) in Cash	(2,491)	1,962	1,
Cash at Beginning of Period	456	2,064	
Cash at End of Period	$ (2,035)	$ 4,026	$ 1,

For the Six Months Ended June 30, 2004 — Condensed Consolidated Cas

($ in thousands)	Guarantor Subsidiaries	Parent	Eliminati
Cash Flow From Operating Activities	$ 7,635	$ 25,068	$ (1,
Cash Flow From Investing Activities	(4,498)	(37,212)	
Cash Flow From Financing Activities	(2,378)	16,925	1,
Net Increase in Cash	759	4,781	
Cash at Beginning of Period	701	1,576	
Cash at End of Period	$ 1,460	$ 6,357	$

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. In July 2004, but effective May 31, 2004, CRI sold all of the outstanding capital stock of CGI to the shareholders of CRI. (See Note 8.) Financial information by operating segment is presented below:

For the Three Months Ended June 30, 2003	Exploration and Production	Gas Gathering, Marketing and Processing	Intersegment
(Dollars in thousands)			

REVENUES:			
Oil and gas sales	$ 33,257	$ 90	$ -
Crude oil marketing and trading	39,753	-	-
Change in derivative fair value	104	-	-
Gas gathering, marketing and processing	-	16,356	769
Oil and gas service operations	2,423	-	-
Total revenues	$ 75,537	$ 16,446	$ 769
OPERATING COSTS AND EXPENSES:			
Production expenses	10,291	52	-
Production taxes	2,352	9	-
Exploration	2,541	10	-
Crude oil marketing and trading	39,392	-	-
Gas gathering, marketing and processing	-	15,024	769
Oil and gas service operations	1,340	-	-
Depreciation, depletion and amortization of oil and gas properties	6,720	194	-
Depreciation and amortization of other property and equipment	543	688	-
Property impairments	1,279	(3)	-
Asset retirement accretion	354	4	-
General and administrative	2,488	210	-
Total operating costs and expenses	$ 67,300	$ 16,188	$ 769
Total operating income	$ 8,237	$ 258	$ -
OTHER INCOME (EXPENSE):			
Interest income	720	2	(694)
Interest expense	(5,589)	(69)	694
Other income, net	11	2	-
Gain on disposition of assets	277	-	-
Total other income (expense)	$ (4,581)	$ (65)	$ -
Net income	$ 3,656	$ 193	$ -
Total assets	$ 464,719	$ 33,590	$ (21,426)
Capital expenditures	$ 23,620	$ 1,370	$ -

For the Three Months Ended June 30, 2004	Exploration and Production	Gas Gathering, Marketing and Processing	Intersegment
(Dollars in thousands)			
REVENUES:			
Oil and gas sales	$ 39,925	$ 182	$ -
Crude oil marketing and trading	56,606	-	-
Change in derivative fair value	800	-	-
Gas gathering, marketing and processing	-	23,849	(4,412)
Oil and gas service operations	2,609	-	-

Total revenues	$ 99,940	$ 24,031	$ (4,412)
OPERATING COSTS AND EXPENSES:			
Production expenses	10,010	69	-
Production taxes	2,619	17	-
Exploration	3,216	-	-
Crude oil marketing and trading	56,727	-	-
Gas gathering, marketing and processing	-	21,712	(4,412)
Oil and gas service operations	1,424	-	-
Depreciation, depletion and amortization of oil and gas properties	9,576	14	-
Depreciation and amortization of other property and equipment	351	932	-
Property impairments	1,802	-	-
Asset retirement accretion	251	4	-
General and administrative	2,567	228	-
Total operating costs and expenses	$ 88,543	$ 22,976	$ (4,412)
Total operating income	$ 11,397	$ 1,055	$ -
OTHER INCOME (EXPENSE):			
Interest income	367	2	(353)
Interest expense	(5,613)	(191)	353
Other income, net	18	1	-
Loss on disposition of assets	(68)	-	-
Total other income (expense)	$ (5,296)	$ (188)	$ -
Net income	$ 6,101	$ 867	$ -
Total assets	$ 467,139	$ 51,299	$ (13,834)
Capital expenditures	$ 19,143	$ 2,071	$ -

For the Six Months Ended June 30, 2003	Exploration and Production	Gas Gathering, Marketing and Processing	Intersegment
(Dollars in thousands)			
REVENUES:			
Oil and gas sales	$ 68,787	$ 282	$ -
Crude oil marketing and trading	80,348	-	-
Change in derivative fair value	407	-	-
Gas gathering, marketing and processing	-	28,360	(1,510)
Oil and gas service operations	4,305	-	-
Total revenues	$ 153,847	$ 28,642	$ (1,510)
OPERATING COSTS AND EXPENSES:			
Production expenses	19,653	102	-
Production taxes	5,011	24	-
Exploration	4,021	32	-
Crude oil marketing and trading	79,876	-	-
Gas gathering, marketing and processing	-	26,131	(1,510)

Oil and gas service operations	2,732	-	-
Depreciation, depletion and amortization of oil and gas properties	15,270	(53)	-
Depreciation and amortization of other property and equipment	1,068	1,311	-
Property impairments	2,552	-	-
Asset retirement accretion	703	6	-
General and administrative	4,958	365	-
Total operating costs and expenses	$ 135,844	$ 27,918	$ (1,510)
Total operating income	$ 18,003	$ 724	$ -
OTHER INCOME (EXPENSE):			
Interest income	809	4	(754)
Interest expense	(10,541)	(129)	754
Other income, net	48	2	-
Gain (loss) on disposition of assets	278	(8)	-
Total other income (expense)	$ (9,406)	$ (131)	$ -
Total income from operations	$ 8,597	$ 593	$ -
Cumulative effect of change in accounting principle	274	1,888	-
Net income	$ 8,871	$ 2,481	$ -
Total assets	$ 464,719	$ 33,590	$ (21,426)
Capital expenditures	$ 49,912	$ 2,816	$ -

For the Six Months Ended June 30, 2004	Exploration and Production	Gas Gathering, Marketing and Processing	Intersegment
(Dollars in thousands)			
REVENUES:			
Oil and gas sales	$ 75,911	$ 319	$ -
Crude oil marketing and trading	112,311	-	-
Change in derivative fair value	404	-	-
Gas gathering, marketing and processing	-	44,899	(9,597)
Oil and gas service operations	4,723	-	-
Total revenues	$ 193,349	$ 45,218	$ (9,597)
OPERATING COSTS AND EXPENSES:			
Production expenses	20,490	138	-
Production taxes	5,190	29	-
Exploration	5,308	-	-
Crude oil marketing and trading	112,590	-	-
Gas gathering, marketing and processing	-	40,705	(9,597)
Oil and gas service operations	3,370	-	-
Depreciation, depletion and amortization of oil and gas properties	20,021	36	-

Depreciation and amortization of other property and equipment	699	1,749	-
Property impairments	3,699	-	-
Asset retirement accretion	523	8	-
General and administrative	4,789	506	-
Total operating costs and expenses	$ 176,679	$ 43,171	$ (9,597)
Total operating income	$ 16,670	$ 2,047	$ -
OTHER INCOME (EXPENSE):			
Interest income	392	4	(353)
Interest expense	(10,708)	(385)	353
Other income, net	30	12	-
Loss on disposition of assets	(103)	-	-
Total other income (expense)	$ (10,389)	$ (369)	$ -
Net income	$ 6,281	$ 1,678	$ -
Total assets	$ 467,139	$ 51,299	$ (13,834)
Capital expenditures	$ 38,474	$ 3,430	$ -

7. COMPREHENSIVE INCOME:

The components of total comprehensive income for the three and six months ended June 30, 2003 and 2004 are as follows:

	Three Months Ended June 30,		Six Months Ended Jun	
	2003	2004	2003	
(Dollars in thousands)	(restated)		(restated)	
Net Income	$ 3,849	$ 6,968	$ 11,352	$
Other Comprehensive Income (loss) - net of income tax:				
Deferred Hedging Gain (loss)	-	350	-	
Total Comprehensive Income	$ 3,849	$ 7,318	$ 11,352	$

8. SUBSEQUENT EVENTS:

On July 19, 2004, CRI paid a cash dividend of $14.9 million to its shareholders.

On July 21, 2004, CRI purchased $7.65 million of its 10-1/4% Senior Subordinated Notes due August 1, 2008, from its principal shareholder, Harold Hamm, and certain of his affiliates. Through June 30, 2004, CRI has purchased an aggregate of $30.5 million principal amount of these Senior Subordinated Notes.

On July 21, 2004, CRI completed the sale of all of its Continental Gas, Inc., or CGI, stock to its shareholders, Harold Hamm and Bert Mackie, as Trustee of the Harold Hamm DST Trust (the "DST Trust") and of the Harold Hamm HJ Trust (the "Buyers") for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided the Company with an opinion of the fairness from a financial point of view, of the sale of CGI to the Buyers. The CGI assets included seven gas gathering systems, three gas-processing plants, and approximately 750 miles of gas gathering lines. These assets represented the entire gas gathering, marketing and processing segment of the Company.

On July 21, 2004, the Company executed the Fourth Amendment to the Credit Agreement that modified the definition to delete any reference to CGI.

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 condensed 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 through the second half of 2004. Relatively high oil and gas prices 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 18 months. Response is occurring as initially simulated by our Resource Development group. Oil production in our Cedar Hills North Unit at June 30, 2004, was approximately 3,500 Bbls per day, an increase of 883 Bbls per day, or BOPD, since November 2003, and 1,300 BOPD over projected primary rates of production without enhanced recovery. During the six months ended June 30, 2004, 9.7 million net barrels of reserves in the Cedar Hills North Unit were moved from proved undeveloped, or PUD, reserves to proved developed producing, or PDP, reserves and 18.9 million net barrels were moved to proved developed non-producing, or PDNP, reserves from PUD reserves. Currently, we anticipate that the 18.9 million barrels will be re-classified to PDP by mid-year 2005 as response to HPAI continues, and our oil production in our Cedar Hills North Unit, on a daily basis, to reach 6,200 BOPD by the end of 2004 and be above 7,100 BOPD by mid-year 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 June 2004:

Property	Monthly Production (Bbls) Nov 2003	Monthly Production (Bbls) Jun 2004	Increase Bbls per Day
Cedar Hills North Unit	69,800	95,400	853
West Cedar Hills Unit	7,700	8,600	30
Total	77,500	104,000	883

Currently, 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 dramatically in the Rocky Mountain Region as response and increased production occurs. We project a reduction of more than $5.00 per barrel in lifting costs by late 2004 or early 2005.

Excluding Cedar Hills, we completed nine wells during the second quarter of 2004, resulting in seven producers and two dry holes for a success rate of 78% for the quarter. Of these nine wells, three are located in the Rocky Mountain region, five wells are in the Mid-Continent region and one well is in the Gulf Coast region. We currently have six wells drilling and nine wells ready for and waiting on completion.

We continue to experience 100% success drilling wells in our Middle Bakken, or MB, project, located in Richland County, Montana. Since completing our first well in the third quarter of 2003, we have drilled and completed 10 wells, (6.1 net wells) to date. These wells have added an estimated 5.5 MMBOE of gross PDP reserves (2.6 MMBOE net) for an average of 548 MBOE per gross well. These reserve figures are in line with expectations. Initial flow rates have ranged from 400 BOPD to 1,600 BOPD. We have invested approximately $3.0 million leasing an additional 28,000 net acres in the MB project during 2004, bringing our total leasehold in the MB project to 92,000 net acres. With this additional leasehold, our inventory of potential wells to drill in the MB project has grown to 126 gross wells and 63 net wells. During the second half of 2004, we anticipate completing an additional seven wells (4.6 net wells) bringing the total producing well count in the MB project to 17 gross wells (10.7 net wells) by year-end 2004. We currently have one rig drilling in MB and plan to add a second rig in the third quarter of 2004 and a third rig in the fourth quarter of 2004.

Using the MB project as our model, we have expanded our search for Bakken oil reserves into North Dakota. During the first half of 2004, we have invested approximately $8.7 million acquiring 232,000 net leasehold acres on opportunities in North Dakota identified by our geotechnical staff. Drilling evaluation of this leasehold has begun and will continue through year-end. The net reserve potential of these new leases could exceed those in the MB project but remains unproven at this time.

As a result of the additional leasing in MB and the new North Dakota projects, leasing expenditures for 2004 are projected to total an estimated $20.0 million or $12.3 million over the $7.7 million originally budgeted for the year.

During the second quarter of 2004, we agreed to sell a 60% working interest in our Stanley Cup project located in Saskatchewan, Canada, to three industry partners on a promoted basis to accelerate development and mitigate risk of not developing this promising prospect. Stanley Cup is a horizontal Red River project similar to the Cedar Hills field with reserve potential of up to 24 MMBO. Drilling is anticipated to begin in the third quarter of 2004.

We have recently elected to discontinue our participation in the Challenger Minerals Inc. Gulf of Mexico venture. Although our five-year results have been profitable, we believe these dollars can be more profitably invested in other Company projects. We will continue to develop the East Island and Breton Sound projects; however, we are contemplating selling and monetizing all other Gulf of Mexico assets. We have an insurance claim on a Eugene Island well, and if successful, we should receive approximately $0.6 million that would be booked to other income in the third quarter of 2004.

We have decided to package and sell all undeveloped leasehold in the Black Warrior Basin in Mississippi. As noted in our 2003 annual report, drilling results have not met expectations. The Smith Creek project is the only project in the basin where we anticipate drilling additional wells over the next 12 months.

During the first half of 2004, the plant throughput in our Matli gas processing system was 2.8 Bcf, an increase of 1.1 Bcf, or 58% over the Matli plant throughput in the first half of 2003.

Our capital expenditure budget for 2004 is $83.3 million. Through the end of the first half of 2004, our aggregate capital expenditures were $41.9 million.

THREE MONTHS ENDED JUNE 30, 2003, COMPARED TO THREE MONTHS ENDED JUNE 30, 2004

Certain reclassifications have been made to prior year amounts to conform to the current year presentation.

The following table shows our income statements for the second quarter of 2003 compared to the second quarter of 2004 with dollar and percentage increases or decreases:

	Three Months Ended June 30,		Increase
REVENUES:	2003	2004	(Decrease)
Oil and gas sales	$ 33,347	$ 40,107	$ 6,760
Crude oil marketing and trading	39,753	56,606	16,853
Change in derivative fair value	104	800	696
Gas gathering, marketing and processing	17,125	19,437	2,312
Oil and gas service operations	2,423	2,609	186
Total revenues	$ 92,752	$ 119,559	$ 26,807
OPERATING COSTS AND EXPENSES:			
Production	$ 10,342	$ 10,079	$ (263)
Production taxes	2,361	2,636	275
Exploration	2,551	3,216	665
Crude oil marketing and trading	39,392	56,727	17,335
Gas gathering, marketing and processing	15,793	17,300	1,507
Oil and gas service operations	1,341	1,424	83
DD&A of oil and gas properties	6,914	9,590	2,676
D&A of other assets	1,231	1,283	52
Property impairments	1,276	1,802	526
Asset retirement obligation accretion	358	255	(103)
General and administrative	2,698	2,795	97
Total operating costs and expenses	$ 84,257	$ 107,107	$ 22,850
OPERATING INCOME	$ 8,495	$ 12,452	$ 3,957
OTHER INCOME (EXPENSE):			
Interest income	$ 28	$ 16	$ (12)
Interest expense	(4,964)	(5,451)	(487)
Other income, net	13	19	6
Gain (loss) on disposition of assets	277	(68)	(345)
Total other income (expense)	$ (4,646)	$ (5,484)	$ (838)

NET INCOME	$ 3,849	$ 6,968	$ 3,119	

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 June 30,	
	2003	2004
NET PRODUCTION:		
Oil (MBbl)	884	858
Gas (MMcf)	2,590	2,147
Oil equivalent (MBoe)	1,316	1,216
OIL AND GAS SALES (dollars in thousands)		
Oil sales, excluding hedges	$ 24,660	$ 30,467
Hedges	(2,579)	(1,270)
Total oil sales, including hedges	22,081	29,197
Gas sales	11,266	10,910
Total oil and gas sales	$ 33,347	$ 40,107
AVERAGE SALES PRICE:		
Oil, excluding hedges (dollar per barrel)	$ 27.90	$ 35.50
Oil, including hedges (dollar per barrel)	$ 24.98	$ 34.02
Gas (dollar per Mcf)	$ 4.35	$ 5.08
Oil equivalent, excluding hedges (dollar per Boe)	$ 27.30	$ 34.02
Oil equivalent, including hedges (dollar per Boe)	$ 25.35	$ 32.98
EXPENSES (dollars per Boe):		
Production expenses (including taxes)	$ 9.65	$ 10.46
General and administrative	$ 2.05	$ 2.30
DD&A (on oil and gas properties)	$ 5.25	$ 7.89

REVENUES

GENERAL

The increase in revenues is attributable to higher oil and gas prices realized on our oil and gas 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 June 30, 2004, compared to the same period in 2003 primarily due to increased prices and our acquisition of the Carmen Gathering System in July 2003, which increased our total throughput.

OIL AND GAS SALES

The increase in oil and gas sales revenues was primarily attributable to higher oil and gas prices in the 2004 period even though volumes decreased to 1,216 thousand barrels of oil equivalent, or MBoe, in the three months ended June 30, 2004, from 1,316 MBoe during the three months ended June 30, 2003.

The following table shows our production by region for the three months ended June 30, 2003 and 2004:

	Three Months Ended June 30,			
	2003		2004	
	MBoe	Percent	MBoe	Percent
Rocky Mountain	752	57.14%	758	62.34%
Mid-Continent	399	30.32%	357	29.36%
Gulf	165	12.54%	101	8.30%
	1,316	100.00%	1,216	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 second 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 June 30, 2004, crude oil marketing revenues were $9.9 million and crude oil marketing expenses were $10.1 million related to such trading activities. 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. Effective May 2004, we closed out all open trading positions and have terminated our derivative trading activities.

CHANGE IN DERIVATIVE FAIR VALUE

The change in derivative fair value for the three months ended June 30, 2003, is related to a crude oil derivative contract used to reduce our exposure to changes in crude oil prices that 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 June 30, 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 second quarter of 2004 was attributable to increased throughput volumes resulting from growth in our existing systems, increase in product prices, and our acquisition of the Carmen Gathering System in July 2003.

OIL AND GAS SERVICE OPERATIONS

We started selling HPAI services to a third party in 2004 which increased our oil and gas service operations $0.6 million in the second quarter of 2004 compared to the second quarter of 2003. This increase was mostly offset by a decrease of $0.3 million in equipment rental income for the second quarter of 2004.

COSTS AND EXPENSES

PRODUCTION EXPENSES AND TAXES

Our production expenses including taxes for the second quarter of 2004 compared to the second quarter of 2003 did not change significantly, but the 8% decrease in volumes for the same periods caused our production expenses including taxes per BOE for the second quarter of 2004 to increase to $10.46 from $9.65 for the second quarter of 2003.

EXPLORATION EXPENSES

The increase in exploration expense was primarily due to an increase in our dry hole costs in the Gulf Coast region, which were amplified by significant mechanical problems and cost overruns while drilling the Shaffer D-2 well in Nueces County, Texas.

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 second quarter of 2004 was attributable to increased throughput volumes resulting from growth in our existing systems, increased product prices, 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 for the second quarter of 2004 compared to the second quarter of 2003 was immaterial.

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

Depletion increased $2.7 million in the second quarter of 2004 compared to the second quarter of 2003, due to adjustments to the mid-year reserve report and certain developmental dry hole costs being added to our amortization base and depleted with the costs of the related property offsets. In the second quarter of 2004, our DD&A expense on our oil and gas properties was calculated at $7.89 per BOE, compared to $5.25 per BOE for the second quarter of 2003. The decrease in volumes for the 2004 period also contributed to a higher DD&A expense per BOE in 2004.

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 June 30, 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 for the second quarter of 2004 compared to the second quarter of 2003 did not change significantly, but the decrease in volumes for the same periods caused our G&A expense per BOE for the second quarter of 2004 to increase to $2.30 from $2.05 for the second 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 second quarter of 2004 compared to the second quarter of 2003.

SIX MONTHS ENDED JUNE 30, 2003, COMPARED TO SIX MONTHS ENDED JUNE 30, 2004.

Certain reclassifications have been made to prior year amounts to conform to the current year presentation.

The following table shows our income statement for the six months ended June 30, 2003, compared to the six months ended June 30, 2004, with dollar and percentage increases or decreases:

	Six Months Ended June 30,		Increase
REVENUES:	2003	2004	(Decrease)
Oil and gas sales	$ 69,069	$ 76,230	$ 7,161
Crude oil marketing and trading	80,348	112,311	31,963
Change in derivative fair value	407	404	(3)
Gas gathering, marketing and processing	26,850	35,302	8,452
Oil and gas service operations	4,305	4,723	418
Total revenues	$ 180,979	$ 228,970	$ 47,991
OPERATING COSTS AND EXPENSES:			
Production	$ 19,755	$ 20,628	$ 873
Production taxes	5,035	5,219	184
Exploration	4,053	5,308	1,255
Crude oil marketing and trading	79,876	112,590	32,714
Gas gathering, marketing and processing	24,621	31,108	6,487
Oil and gas service operations	2,732	3,370	638
DD&A of oil and gas properties	15,217	20,057	4,840
D&A of other assets	2,379	2,448	69
Property impairments	2,552	3,699	1,147
Asset retirement obligation accretion	709	531	(178)
General and administrative	5,323	5,295	(28)

Total operating costs and expenses	$ 162,252	$ 210,253	$ 48,001
OPERATING INCOME	$ 18,727	$ 18,717	$ (10)
OTHER INCOME (EXPENSE):			
Interest income	$ 59	$ 43	$ (16)
Interest expense	(9,916)	(10,740)	(824)
Other income, net	50	42	(8)
Gain (loss) on sale of assets	270	(103)	(373)
Total other income (expense)	$ (9,537)	$ (10,758)	$ (1,221)
INCOME BEFORE CHANGE IN ACCOUNTING PRINCIPLE	$ 9,190	$ 7,959	$ (1,231)
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	$ 2,162	$ -	$ (2,162)
NET INCOME	$ 11,352	$ 7,959	$ (3,393)

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 Six Months Ended June 30,	
	2003	2004
NET PRODUCTION:		
Oil (MBbl)	1,791	1,646
Gas (MMcf)	4,958	4,469
Oil equivalent (MBoe)	2,617	2,390
OIL AND GAS SALES (dollars in thousands)		
Oil sales, excluding hedges	$ 52,775	$ 55,917
Hedges	(7,305)	(1,724)
Total oil sales, including hedges	45,470	54,193
Gas sales	23,599	22,037
Total oil and gas sales	$ 69,069	$ 76,230
AVERAGE SALES PRICE:		
Oil, excluding hedges (dollar per barrel)	$ 29.47	$ 33.98
Oil, including hedges (dollar per barrel)	$ 25.39	$ 32.93
Gas (dollar per Mcf)	$ 4.76	$ 4.93
Oil equivalent, excluding hedges (dollar per Boe)	$ 29.18	$ 32.61
Oil equivalent, including hedges (dollar per Boe)	$ 26.39	$ 31.89
EXPENSES (dollars per Boe):		
Production expenses (including taxes)	$ 9.47	$ 10.81
General and administrative	$ 2.03	$ 2.22
DD&A (on oil and gas properties)	$ 5.81	$ 8.39

REVENUES

GENERAL

Our revenues increased due to higher oil and gas prices realized on our oil and gas production and an increase in volumes from our oil marketing and trading programs. Gas gathering, marketing and processing revenues were higher for the six months ended June 30, 2004, compared to the six months ended June 30, 2003, due to higher prices and the acquisition of the Carmen Gathering System that increased our total throughput.

OIL AND GAS SALES

Although our volumes for the first six months of 2004 decreased 227 MBoe compared to the first six months of 2003, our oil and gas sales revenues for the six months of 2004 increased compared to the first six months of 2003 due to higher oil and gas prices.

The following table shows our production by region for the six months ended June 30, 2003 and 2004:

	Six Months Ended June 30,			
	2003		2004	
	MBoe	Percent	MBoe	Percent
Rocky Mountain	1,523	58.20%	1,439	60.21%
Mid-Continent	790	30.19%	726	30.38%
Gulf	304	11.61%	225	9.41%
	2,617	100.00%	2,390	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 six months 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 six months ended June 30, 2004, crude oil marketing revenues were $20.2 million and crude oil marketing expenses were also $20.4 million, related to such trading activities. 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 six months ended June 30, 2003, is related to a crude oil derivative contract used to reduce our exposure to changes in crude oil prices that 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 six months ended June 30, 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 six months of 2004 was attributable to increased throughput volumes resulting from growth in our existing systems, increased product prices, and the acquisition of the Carmen Gathering system in July 2003.

OIL AND GAS SERVICE OPERATIONS

We started selling HPAI services to a third party in 2004 which increased our oil and gas service operations $0.6 million in the first six months of 2004 compared to the first six months of 2003. This increase was offset by a decrease of $0.2 million in saltwater disposal fees due to shut-in wells in the first six months of 2004.

COSTS AND EXPENSES

PRODUCTION EXPENSES AND TAXES

Our production expense including taxes for the first six months of 2004 compared to the first six months of 2003 did not change significantly, but the 9% decrease in volumes from the same periods caused our production expenses including taxes per BOE for the first six months of 2004 to increase to $10.81 from $9.47 for the first six months of 2003.

EXPLORATION EXPENSES

The increase in exploration expense was primarily due to an increase in our dry hole costs in the Gulf Coast region, which were amplified by significant mechanical problems and cost overruns associated with the Shaffer D-2 well in Nueces County, Texas in the first six months of 2004 compared to the first six months of 2003.

CRUDE OIL MARKETING AND TRADING

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

GAS GATHERING, MARKETING, AND PROCESSING

During the six months ended June 30, 2004, gas gathering, marketing and processing expenses increased over the six months ended June 30, 2003 due to increased throughput volumes from growth in our existing systems, increased product prices, and the acquisition of the Carmen Gathering System in July 2003.

OIL AND GAS SERVICE OPERATIONS

The increase in our oil and gas service operations expense was due to high prices paid for purchasing and treating reclaimed oil for resale.

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

For the six months ended June 30, 2004, DD&A of our oil and gas properties increased due to certain developmental dry hole costs being added to our amortization base and depleted with the costs of the related property offsets and due to slightly higher production decline rates in the Gulf Coast region. In the first six months of 2004, our DD&A expense on oil and gas properties was calculated at $8.39 per BOE compared to $5.81 per BOE for the first six months of 2003. The decrease in volumes for the 2004 period also contributed to a higher DD&A expense per BOE in 2004.

DEPRECIATION AND AMORTIZATION OF OTHER ASSETS ("D&A")

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

PROPERTY IMPAIRMENTS

The increase in our property impairments for the six months ended June 30, 2004 compared to the six months ended June 30, 2003, was primarily due to increased impairment on capitalized costs of our undeveloped leasehold.

ASSET RETIREMENT ACCRETION

Recalculation of our asset retirement obligation lowered our obligation and accretion expense in the first six months of 2004 compared to the first six months of 2003.

GENERAL AND ADMINISTRATIVE (G&A)

Our G&A expense for the first half of 2004 compared to the first half of 2003 did not change significantly, but the decrease in volumes from the same periods caused our G&A expense per BOE for the first half of 2004 to increase to $2.22 from $2.03 for the first half 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 six months ended June 30, 2004, compared to the six months ended June 30, 2003.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOW FROM OPERATIONS

Net cash provided by our operating activities for the six months ended June 30, 2004, was $31.6 million, an increase of $3.9 million from $27.7 million provided by our operating activities during the comparable 2003 period. Our cash balance as of June 30, 2004, was $7.8 million, an increase of $5.5 million from our cash balance of $2.3 million held at December 31, 2003.

DEBT

Our long-term debt at December 31, 2003, and June 30, 2004, consisted of the following:

(Dollars in thousands)	December 31, 2003	June 30, 2004
10.25% Senior Subordinated Notes due August 1, 2008	$ 127,150	$ 127,150
Credit Facility due March 31, 2007	132,900	128,049

Credit Facility due March 31, 2006	-	25,000
Credit Facility due September 30, 2006	17,000	15,786
Capital Lease Agreement	13,827	12,159
Ford Credit	43	36
Outstanding Debt	290,920	308,180
Less Current Portion	5,776	5,776
Total Long-Term Debt	$ 285,144	$ 302,404

CREDIT FACILITY

On July 21, 2004, the Company executed the Fourth Amendment to the credit Agreement that modified the definitions to delete any reference to CGI. (See Note 8.)

On April 14, 2004, we executed the Third Amendment to our secured credit agreement that added a $25.0 million term credit facility that matures on March 31, 2006. The amendment also extended the maturity date of the original facility to March 31, 2007. Borrowings under the term credit facility have margins of 5.5% on LIBOR loans and 3% on prime loans. On April 14, 2004, we drew $25 million on the new term credit facility and paid down the balance of the original revolving credit facility. Borrowings under the revolving 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 4.2% at June 30, 2004. The borrowing base of our credit facility was $150.0 million on June 30, 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.

A cash dividend paid to our shareholders on July 19, 2004, was funded with short-term borrowings under our credit facility and we used corporate funds to acquire $7.65 million of our 10-1/4% Senior Subordinated Notes on July 21, 2004. (See Note 8.)

At August 13, 2004, the outstanding balances were $137.0 million and $25.0 million on the original revolving credit facility and the term loan, respectively.

On October 22, 2003, our subsidiary, 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. 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 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 June 30, 2004, the outstanding balance on CGI's credit facility was $15.8 million. On July 21, 2004, but effective May 31, 2004, we sold all of the outstanding capital stock of CGI to our shareholders. Section 4.10 of our indenture requires that within 360 days after the receipt of any net proceeds from any asset sale, we may apply such net proceeds, at our option, in any order or combination, (a) to reduce Senior Debt or Guarantor Senior Debt, (b) to make permitted investments, (c) to make investments in interests in oil and gas businesses or (d) to make capital expenditures in respect of our Restricted Subsidiaries' oil and gas business. Pending the final application of any such net proceeds, we may temporarily reduce indebtedness under our revolving credit facility or otherwise invest such net proceeds in any manner that is not prohibited by the indenture. We intend to use the proceeds from the sale of the stock of CGI to fund our drilling program for the next six months.

Our credit agreement contains certain financial and other covenants. At June 30, 2004, we were in compliance with all of the covenants.

CAPITAL EXPENDITURES

Our 2004 capital expenditures budget, exclusive of acquisitions, is $83.3 million, of which $6.7 million is dedicated to our Cedar Hills Field secondary recovery project. During the six months ended June 30, 2004, we incurred $41.9 million of capital expenditures, compared to $52.7 million during the comparable six- month period of 2003. Of the total $41.9 million of capital expenditures, we expended $27.2 million in exploration and development, $5.0 million on secondary recovery operations, and $5.3 million on leasing. We used the majority of the remaining $4.4 million for additions to our gas gathering systems. The $10.8 million decrease in our capital expenditures during the first six months of 2004 compared to the first six months of 2003 was the result of our 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. At August 13, 2004, we had $13.0 million of availability at 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 or minus 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 June 30, 2004, we had collars and/or floors in place covering approximately 1.0 million barrels of crude oil representing approximately 50% of our forecasted production through December 30, 2004. At June 30, 2004, we had a mark-to-market unrealized loss of approximately $645,700 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 June 30, 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. The 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 June 30, 2004:

	2004	2005	2006	2007
Natural Gas Physical Delivery Contracts:				
Contract Volumes (MMBtu)	300,000	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
	Aug 2004	62,000	$ 37.72
	Sep 2004	30,000	$ 41.09

Crude Oil Collars and Floors for 2004:	Contract Volumes (Bbls)	Weighted-average Fixed Price per Bbl
July - Oct, Floor	602,000	$ 22.00
Sept - Oct, Floor	200,000	$ 24.00
Nov - Dec, Floor	230,000	$ 24.50
	1,032,000	
July - Oct, Ceiling	460,000	$ 36.00
Nov - Dec, Ceiling	230,000	$ 45.00
	690,000	

The following table represents our fixed basis contracts in place at June 30, 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
Aug 2004	62,000	$ 37.72
Sep 2004	30,000	$ 41.09

TRADING

In the first half 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 June 30, 2004, we had no open trading derivative contracts in place.

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	Tota
Fixed rate debt:						
Senior subordinated						