

CONTINENTAL RESOURCES INC

Form 10-Q

August 08, 2008

[Table of Contents](#)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

**x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE
ACT OF 1934**

For the quarterly period ended June 30, 2008

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: 001-32886

CONTINENTAL RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

Oklahoma
(State or other jurisdiction of
incorporation or organization)

73-0767549
(I.R.S. Employer
Identification No.)

302 N. Independence, Suite 1500, Enid, Oklahoma
(Address of principal executive offices)

73701
(Zip Code)

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

Former name, former address and former fiscal year, if changed since last report: Not applicable

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 ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐

Accelerated filer ☐

Non-accelerated filer ☒

Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. 169,230,520 common shares were outstanding on July 31, 2008.

Table of Contents

CONTINENTAL RESOURCES, INC.

FORM 10-Q

Quarter Ended June 30, 2008

Unless the context otherwise indicates, all references in this report to Continental, Company, we, us, or our are to Continental Resources, Inc. and its subsidiary.

TABLE OF CONTENTS

PART I. Financial Information

ITEM 1.	<u>Financial Statements</u>	4
	<u>Condensed Consolidated Balance Sheets</u>	5
	<u>Unaudited Condensed Consolidated Statements of Operations</u>	6
	<u>Condensed Consolidated Statements of Shareholders' Equity</u>	7
	<u>Unaudited Condensed Consolidated Statements of Cash Flows</u>	8
	<u>Notes to Unaudited Condensed Consolidated Financial Statements</u>	9
ITEM 2.	<u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	14
ITEM 3.	<u>Quantitative and Qualitative Disclosures About Market Risk</u>	24
ITEM 4.	<u>Controls and Procedures</u>	25

PART II. Other Information

ITEM 1.	<u>Legal Proceedings</u>	26
ITEM 1A.	<u>Risk Factors</u>	26
ITEM 2.	<u>Unregistered Sales of Equity Securities and Use of Proceeds</u>	26
ITEM 3.	<u>Defaults Upon Senior Securities</u>	26
ITEM 4.	<u>Submission of Matters to a Vote of Security Holders</u>	26
ITEM 5.	<u>Other Information</u>	26
ITEM 6.	<u>Exhibits</u>	26
	<u>Signature</u>	27
	<u>Index to Exhibits</u>	28
	<u>Certifications Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002</u>	
	<u>Certifications Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002</u>	

Table of Contents

Glossary of Oil and Natural Gas Terms

The terms defined in this section are used throughout this report:

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Enhanced recovery. The recovery of oil and natural gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Enhanced recovery methods are often applied when production slows due to depletion of the natural pressure.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differ from nearby rock.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

MBoe. One thousand Boe.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Working interest. The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Table of Contents

PART I. Financial Information

ITEM 1. Financial Statements

On May 14, 2007, the Company completed its initial public offering. In conjunction therewith, the Company effected an 11 for 1 stock split by means of a stock dividend. All prior period share and per share information contained in this report have been retroactively restated to give effect to the stock split. On May 14, 2007, the Company amended its certificate of incorporation to, among other things, increase the number of authorized preferred shares to 25 million and common shares to 500 million. Prior to completion of the public offering, the Company was a subchapter S corporation and income taxes were payable by its shareholders. In connection with the public offering, the Company converted to a subchapter C corporation and recorded a charge to earnings of \$198.4 million to recognize deferred taxes at May 14, 2007. Thereafter, the Company has provided for income taxes on income.

Table of Contents

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Balance Sheets

	June 30, 2008 (Unaudited)	December 31, 2007
(In thousands, except par values and share data)		
Assets		
Current assets:		
Cash and cash equivalents	\$ 13,190	\$ 8,761
Receivables:		
Oil and natural gas sales	149,807	95,165
Affiliated parties	33,725	17,146
Joint interest and other, net	92,233	50,779
Inventories	27,038	19,119
Deferred and prepaid taxes	2,028	12,159
Prepaid expenses and other	3,014	2,435
Total current assets	321,035	205,564
Net property and equipment, based on successful efforts method of accounting	1,492,000	1,157,926
Debt issuance costs, net	1,444	1,683
Total assets	\$ 1,814,479	\$ 1,365,173
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	\$ 191,770	\$ 127,730
Accounts payable trade to affiliated parties	16,958	15,090
Accrued liabilities and other	52,881	25,295
Revenues and royalties payable	85,566	67,349
Unrealized derivative losses		26,703
Current portion of asset retirement obligation	3,042	3,939
Total current liabilities	350,217	266,106
Long-term debt	220,000	165,000
Other noncurrent liabilities:		
Deferred tax liability	359,181	271,424
Asset retirement obligation, net of current portion	40,279	38,153
Other noncurrent liabilities	1,407	1,358
Total other noncurrent liabilities	400,867	310,935
Commitments and contingencies (Note 7)		
Shareholders equity:		
Preferred stock, \$0.01 par value: 25,000,000 shares authorized; no shares issued and outstanding		
Common stock, \$0.01 par value; 500,000,000 shares authorized, 169,231,349 shares issued and outstanding at June 30, 2008; 168,864,015 shares issued and outstanding at December 31, 2007	1,692	1,689
Additional paid-in-capital	420,417	415,435
Retained earnings	421,286	206,008
Total shareholders equity	843,395	623,132

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

Total liabilities and shareholders' equity	\$	1,814,479	\$	1,365,173
--	----	-----------	----	-----------

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

Table of Contents

Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Operations

	Three Months Ended June 30, 2008		Six Months Ended June 30, 2007	
	(In thousands, except per share data)		(In thousands, except per share data)	
Revenues:				
Oil and natural gas sales	\$ 278,311	\$ 132,282	\$ 487,010	\$ 240,794
Oil and natural gas sales to affiliates	19,308	7,764	36,034	15,236
Loss on mark-to-market derivative instruments	(3,358)		(7,966)	
Oil and natural gas service operations	9,173	5,280	16,007	10,419
Total revenues	303,434	145,326	531,085	266,449
Operating costs and expenses:				
Production expenses	22,868	16,591	41,818	28,615
Production expense to affiliates	4,085	5,064	8,208	9,025
Production tax	17,695	7,437	30,470	13,600
Exploration expense	5,731	1,602	10,993	3,906
Oil and natural gas service operations	6,468	3,134	10,698	6,353
Depreciation, depletion, amortization and accretion	28,062	23,330	56,708	43,738
Property impairments	3,153	5,923	7,673	8,893
General and administrative	10,276	8,450	17,807	21,423
Gain on sale of assets	(133)	(339)	(212)	(400)
Total operating costs and expenses	98,205	71,192	184,163	135,153
Income from operations	205,229	74,134	346,922	131,296
Other income (expense):				
Interest expense	(2,865)	(3,427)	(6,276)	(7,080)
Other	248	584	547	889
	(2,617)	(2,843)	(5,729)	(6,191)
Income before income taxes	202,612	71,291	341,193	125,105
Provision for income taxes	75,305	213,789	125,915	213,789
Net income (loss)	\$ 127,307	\$ (142,498)	\$ 215,278	\$ (88,684)
Basic net income (loss) per share	\$ 0.76	\$ (0.87)	\$ 1.28	\$ (0.55)
Diluted net income (loss) per share	\$ 0.75	\$ (0.87)	\$ 1.27	\$ (0.55)
Dividends per share				0.33
Pro forma (unaudited):				
Income before income taxes		\$ 71,291		\$ 125,105
Provision for income taxes		27,091		47,540
Net income		\$ 44,200		\$ 77,565
Basic net income per share		\$ 0.27		\$ 0.48
Diluted net income per share		\$ 0.27		\$ 0.48

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

Table of Contents

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Statements of Shareholders' Equity

	Shares outstanding	Common stock	Additional paid-in capital (in thousands, except share data)	Retained earnings	Accumulated other comprehensive income (loss)	Total shareholders' equity
Balance, January 1, 2007	159,106,244	\$ 144	\$ 27,087	\$ 463,255	\$ (25)	\$ 490,461
Comprehensive income:						
Net income				28,580		28,580
Other comprehensive income, net of tax					25	25
Total comprehensive income						28,605
Public offering of common stock	8,850,000	89	124,406			124,495
Reclass for stock split		1,447	(1,447)			
Adjust for undistributed earnings from conversion to subchapter C corporation			234,099	(234,099)		
Reclass stock compensation liability to equity			29,828			29,828
Stock-based compensation			3,874			3,874
Tax benefit on share-based compensation plan			1,630			1,630
Stock options:						
Exercised	689,476	7	619			626
Repurchased and canceled	(292,313)	(3)	(3,079)			(3,082)
Restricted stock:						
Issued	629,684	6				6
Repurchased and canceled	(77,441)	(1)	(1,476)			(1,477)
Forfeited	(41,635)		(106)			(106)
Dividends				(51,728)		(51,728)
Balance, December 31, 2007	168,864,015	\$ 1,689	\$ 415,435	\$ 206,008	\$	\$ 623,132
Net income (unaudited)				215,278		215,278
Stock-based compensation (unaudited)			4,746			4,746
Tax benefit on share-based compensation plan (unaudited)			3,255			3,255
Stock options:						
Exercised (unaudited)	319,647	3	1,158			1,161
Repurchased and canceled (unaudited)	(74,179)		(3,853)			(3,853)
Restricted stock:						
Issued (unaudited)	149,149					
Repurchased and canceled (unaudited)	(8,033)		(324)			(324)
Forfeited (unaudited)	(19,250)					
Balance, June 30, 2008 (unaudited)	169,231,349	\$ 1,692	\$ 420,417	\$ 421,286	\$	\$ 843,395

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

Table of Contents

Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Cash Flows

	Six months ended June 30,	
	2008	2007
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	\$ 215,278	\$ (88,684)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	56,656	44,192
Property impairments	7,673	8,893
Change in derivative fair value	(26,703)	
Equity compensation	3,895	10,933
Tax benefit of excess non qualified stock option deduction	(3,255)	
Provision for deferred income taxes	100,811	213,789
Other, net	1,823	1,158
Changes in assets and liabilities:		
Accounts receivable	(112,675)	(29,595)
Inventories	(7,919)	(2,533)
Prepaid expenses and other	(336)	331
Accounts payable	17,918	(5,182)
Revenues and royalties payable	18,217	8,685
Accrued liabilities and other	26,538	1,134
Other noncurrent liabilities	49	388
Net cash provided by operating activities	297,970	163,509
Cash flows from investing activities:		
Exploration and development	(275,504)	(232,494)
Purchase of oil and gas properties	(71,003)	(145)
Purchase of other property and equipment	(3,529)	(2,460)
Proceeds from sale of assets	1,307	1,244
Net cash used in investing activities	(348,729)	(233,855)
Cash flows from financing activities:		
Line of credit	184,000	185,500
Repayment of line of credit and other borrowings	(129,000)	(188,000)
Proceeds from initial public offering, net		124,495
Dividends to shareholders	(6)	(51,833)
Repurchase of equity grants	(4,177)	(518)
Exercise of options	1,161	20
Tax benefit of excess non qualified stock option deduction	3,255	
Debt issuance costs	(45)	(45)
Net cash provided by financing activities	55,188	69,619
Effect of exchange rate changes on cash and cash equivalents		102
Net change in cash and cash equivalents	4,429	(625)
Cash and cash equivalents at beginning of period	8,761	7,018
Cash and cash equivalents at end of period	\$ 13,190	\$ 6,393

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

Table of Contents

Continental Resources, Inc. and Subsidiary

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Business

Description of Company

Continental Resources, Inc.'s (Continental or the Company) principal business is oil and natural gas exploration, development and production. Continental's operations are primarily in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

The accompanying condensed consolidated balance sheet as of December 31, 2007, which has been derived from audited financial statements, and the unaudited condensed consolidated financial statements of Continental as of June 30, 2008 and for the interim periods ended June 30, 2008 and 2007 have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial statements. All significant intercompany accounts and transactions have been eliminated in the condensed consolidated financial statements.

The preparation of these interim financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The most significant of the estimates and assumptions that affect reported results is the estimate of the Company's oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing oil and gas properties. In the opinion of management, all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation in accordance with accounting principles generally accepted in the United States of America have been included in these unaudited interim condensed consolidated financial statements. The results of operations for any interim period are not necessarily indicative of the results of operations for the entire year. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes for the year ended December 31, 2007.

Pro forma information (unaudited)

Pro forma adjustments are reflected on the condensed consolidated statements of operations to provide for income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109, *Accounting for Income Taxes*, as if the Company had been a subchapter C corporation for all periods presented. For unaudited pro forma income tax calculations, deferred tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities were measured using enacted tax rates expected to apply to taxable income in the years in which the Company expects to recover or settle those temporary differences. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for 2007. The pro forma tax effects are based upon currently available information. Management believes that these assumptions provide a reasonable basis for representing the pro forma tax effects.

Net Income Per Common Share

Basic net income per common share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted net income per share reflects the potential dilution of non-vested restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if these options were exercised. Potentially dilutive non-vested restricted shares and stock options were not considered in the calculation of the diluted weighted average shares outstanding used in computing diluted net income per share for the three and six months ended June 30, 2007, because the effect was anti-dilutive. The following table sets forth the computation of basic and diluted weighted shares used in the basic and diluted net income per share computations for the three and six months ended June 30, 2008 and 2007.

Recent Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51* (SFAS 160). SFAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS 160 will change the accounting and reporting for minority interests, which will be re-characterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for the Company for fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. Early adoption is prohibited for both standards. The adoption of SFAS 141(R) and SFAS 160 is not expected to have a material impact on the Company's consolidated financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*, which amends and expands the disclosure requirements of FAS 133 to require qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement will be effective for the Company beginning in fiscal 2009. The adoption of this statement will change the disclosures related to derivative instruments held by the Company, if any.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS No. 162 is effective sixty days following the SEC's approval of PCAOB amendments to AU Section 411, *The Meaning of Present fairly in conformity with generally accepted accounting principles*. SFAS 162 is not expected to have a material impact on the Company's consolidated financial position or results of operations.

Table of Contents**Note 3. Cash Flow Information**

Net cash provided by operating activities reflects cash interest payments of \$5.8 million and \$4.8 million for the six months ended June 30, 2008 and 2007, respectively. Non-cash investing activities consisting of additions to the asset retirement obligations were \$2.1 million and \$774,000 for the six months ended June 30, 2008 and 2007, respectively. The Company paid cash income taxes of \$11.6 million during the six months ended June 30, 2008.

Note 4. Derivatives

In July 2007, the Company entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, the Company received a fixed-price of \$72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has elected not to designate its derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, the Company marked its derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value on derivative instruments in the statements of operations. As of June 30, 2008 the Company had no open derivative positions.

Note 5. Long-term Debt

The Company had \$220.0 million and \$165.0 million in long-term debt outstanding as of June 30, 2008 and December 31, 2007, respectively, on its credit facility.

The credit facility matures on April 12, 2011. At the Company's election, the maturity date can be extended for up to two one-year periods. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months, as elected by the Company, plus a margin ranging from 100 to 175 basis points, depending on the percentage of its borrowing base utilized, or the lead bank's reference rate. The credit facility has a maximum facility amount of \$750.0 million, a borrowing base of \$1.0 billion, subject to semi-annual re-determination, and a commitment level of \$400.0 million. Under the terms of the credit facility, the Company is allowed to set the commitment level up to the lesser of the borrowing base or the maximum facility amount. While the borrowing base is set at \$1.0 billion by the banks based on their valuation of the underlying reserves, the Company could not borrow more than the maximum facility amount of \$750.0 million without amending the agreement. The Company's weighted average interest rate was 3.93% at June 30, 2008.

The Company had \$180.0 million of unused commitments under the Credit Agreement at June 30, 2008 and incurs commitment fees of 0.2% of the daily average excess of the commitment amount over the outstanding credit balance. The credit facility contains certain covenants including that the Company maintain a current ratio of not less than 1.0 to 1.0 (inclusive of availability under the Credit Agreement) and a Total Funded Debt to EBITDAX, as defined, of no greater than 3.75 to 1.0 on a rolling four-quarter basis. The Company was in compliance with these covenants at June 30, 2008.

Note 6. Income Taxes

The following is an analysis of the Company's consolidated income tax provision (benefit) for the periods indicated. The Company converted to a subchapter C corporation on May 14, 2007. Prior to this date, the Company was a subchapter S corporation and income taxes were payable by its shareholders.

	Three months ended June 30, 2008		Six months ended June 30, 2008	
	2008	2007	2008	2007
	(in thousands)			
Current:				
Federal	\$ 13,357	\$ (1,300)	\$ 22,321	\$ (1,300)
State	1,590	(202)	2,783	(202)
Total current tax provision (benefit)	14,947	(1,502)	25,104	(1,502)
Deferred:				

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

Federal	53,937	186,387	90,201	186,387
State	6,421	28,904	10,610	28,904
Total deferred tax provision	60,358	215,291	100,811	215,291
Income tax provision	\$ 75,305	\$ 213,789	\$ 125,915	\$ 213,789

Table of Contents

The following table reconciles the income tax provision with income tax at the Federal statutory rate for the periods indicated:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(in thousands)			
Federal tax at statutory rate	\$ 70,915	\$ 24,952	\$ 119,418	\$ 43,787
State income taxes, net of federal benefit	5,268	2,386	8,871	4,188
Eliminate taxes on earnings prior to subchapter C corporation conversion ⁽¹⁾		(12,388)		(33,025)
Non-deductible stock-based compensation	15	314	15	314
Excess statutory depletion	(205)		(1,053)	
Domestic production activities deduction	(1,271)		(1,987)	
Other, net	583	121	651	121
Deferred taxes recorded upon conversion to a subchapter C corporation		198,404		198,404
Income tax provision	\$ 75,305	\$ 213,789	\$ 125,915	\$ 213,789

⁽¹⁾ Federal tax at statutory rate and state income taxes have been calculated based upon the full net income before tax for the period. However, the Company converted from a subchapter S corporation to a subchapter C corporation on May 14, 2007. This line item eliminates the tax effect related to the net income before tax from the beginning of the period presented through the date of conversion to a subchapter C corporation, which tax effects are already included in the line item deferred taxes recorded upon conversion to a subchapter C corporation. Significant components of the Company's deferred tax assets and liabilities as of June 30, 2008 and December 31, 2007 are as follows:

	June 30, 2008	December 31, 2007
	(in thousands)	
Current:		
Deferred tax assets ⁽¹⁾		
Unrealized losses on derivatives	\$	\$ 10,040
Other expenses	641	602
Total current deferred tax assets	641	10,642
Noncurrent:		
Deferred tax assets		
Net operating loss carryforward		4,553
Alternative minimum tax carryforward	5,272	6,537
Deferred compensation	5,316	1,952
Other	361	438
Total noncurrent deferred tax assets	10,949	13,480
Deferred tax liabilities		
Property and equipment	370,130	284,904
Net noncurrent deferred tax liabilities	359,181	271,424
Net deferred tax liabilities	\$ 358,540	\$ 260,782

⁽¹⁾ Deferred and prepaid taxes on the consolidated balance sheets at June 30, 2008 and December 31, 2007 contain prepaid taxes of \$1.4 million and \$1.2 million, respectively.

Note 7. Commitments and Contingencies

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will have a material adverse effect on the financial position or results of operations of the Company. As of June 30, 2008 and December 31, 2007, the Company has provided a reserve of \$1.1 million and \$1.0 million, respectively, for various matters none of which are believed to be individually significant. Due to the nature of the oil and gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

Table of Contents**Note 8. Stock Compensation**

Effective October 1, 2000, the Company adopted the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and granted options to certain eligible employees. These options were Incentive Stock Options, Nonqualified Stock Options or a combination of both. The granted stock options vest ratably over either a three or five year period commencing on the first anniversary of the grant date and expire ten years from date of grant. On November 10, 2005, the 2000 Plan was terminated.

The Company's stock option grants under the 2000 Plan are as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding December 31, 2007	886,527	\$ 2.28	794,853	\$ 1.88
Exercised	(319,647)	3.63		

Outstanding June 30, 2008	566,880	\$ 1.51	566,880	\$ 1.51
---------------------------	---------	---------	---------	---------

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option. The total intrinsic value of options exercised during the six months ended June 30, 2008 was approximately \$12.9 million. At June 30, 2008, the exercisable options had a weighted average life of 4.21 years. As of June 30, 2008, all stock options were vested.

Restricted Stock

On October 3, 2005, the Company adopted the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) and reserved a maximum of 5,500,000 shares of non-voting common stock that may be issued pursuant to the 2005 Plan. As of June 30, 2008, the Company had 3,812,285 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company's common stock for all corporate purposes during the period of restriction including the right to receive dividends which is subject to forfeiture. Restricted stock grants vest over periods ranging from one to three years.

The Company began issuing shares of restricted common stock to employees and non-employee directors in October 2005. A summary of the status of the unvested shares of restricted stock as of June 30, 2008, and changes during the six months ended June 30, 2008, is presented below:

	Unvested restricted shares	Weighted average grant-date fair value
Unvested restricted shares at January 1, 2008	1,047,706	\$ 18.36
Granted	149,149	21.96
Vested	(39,387)	10.84
Forfeited	(19,250)	26.57

Outstanding June 30, 2008	1,138,218	\$ 18.95
---------------------------	-----------	----------

The fair value of the restricted shares that vested during the six months ended June 30, 2008 at their vesting dates was \$0.4 million. As of June 30, 2008, there was \$14.7 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.49 years.

Note 9. Fair Value Measures

The Company adopted SFAS No. 157, Fair Value Measurements, effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. In

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

February 2008, the FASB issued FASB Staff Position FAS 157-2, which delayed the effective date of SFAS No. 157 by one year for non-financial assets and liabilities. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between

Table of Contents

market participants at the measurement date. SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

- Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter commodity price swaps.
- Level 3: Measures based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity).

As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

During the six months ended June 30, 2008, the Company valued our derivative instruments according to SFAS No. 157 pricing levels. These contracts expired during the second quarter of 2008 and we currently have no financial assets or financial liabilities that are measured on a fair value basis.

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 historical consolidated financial statements and the notes included in our Annual Report on Form 10-K for the year ended December 31, 2007. 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

Continental Resources, Inc. is an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We target large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations.

We principally derive our operating income and cash flow from the sale of oil and natural gas. We expect that growth in our operating income and revenues will primarily depend on our ability to increase our oil and natural gas production and on product prices. In recent years, there has been significant volatility in oil and natural gas prices due to a variety of factors we can not control or predict. These factors, which include weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for oil and natural gas, which affects prices. In addition, the prices we realize for our oil and natural gas production are affected by location differences in market prices.

For the first six months of 2008, our oil and gas production increased to 5,629 MBoe (30,930 Boe per day), up 10% from the first six months of 2007. The increase in 2008 production primarily resulted from an increase in production from our Red River units, Bakken field and Arkoma Woodford shale play. Oil and natural gas revenues for the first six months of 2008 increased by 104% to \$523.0 million due to an 83% increase in price and a 12% increase in sales volumes. Our realized price per Boe increased \$41.82 to \$92.34 for the first six months of 2008 compared to the first six months of 2007. Production expense and production tax increased a combined \$29.3 million, or 57%, and the combined per unit cost

Table of Contents

increased \$4.10 per Boe, or 41%, due to expanded operations, increased workover activity in 2008 and higher production taxes which are generally a function of oil and gas revenue. Oil sales volumes were 35 MBbls more than oil production for the first six months of 2008 and 47 MBbls less for the same period in 2007 due to fluctuations in pipeline linefill and temporarily stored barrels. Our cash flow from operating activities for the six months ended June 30, 2008, was \$298.0 million, an increase of \$134.5 million from the comparable 2007 period. The increase in operating cash flows was mainly due to increases in revenue reflecting increased production volumes and product prices partially offset by higher operating costs. During the six months ended June 30, 2008, we invested \$327.0 million (inclusive of non-cash accruals of \$48.0 million and exclusive of acquisition expenditures of \$71.0 million) in our capital program primarily in the North Dakota Bakken field and the Cedar Hills fields in the Rocky Mountain area and the Arkoma Woodford shale play in the Mid-Continent region.

How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance. Among these measures are (1) volumes of oil and natural gas produced, (2) oil and natural gas prices realized, (3) per unit operating and administrative costs and (4) EBITDAX. The following table contains unaudited financial and operational highlights for the periods indicated.

	Three Months ended June 30,		Six Months ended June 30,	
	2008	2007	2008	2007
Average daily production:				
Oil (Bopd)	24,117	23,674	24,080	23,391
Natural gas (Mcf)	45,035	29,618	41,098	29,229
Oil equivalents (Boepd)	31,623	28,610	30,930	28,262
Average prices: ⁽¹⁾				
Oil (\$/Bbl)	\$ 118.28	\$ 58.25	\$ 104.43	\$ 53.44
Natural gas (\$/Mcf)	8.82	6.07	8.25	6.11
Oil equivalents (\$/Boe)	102.86	54.44	92.34	50.52
Production expense (\$/Boe) ⁽¹⁾	9.32	8.42	8.83	7.43
General and administrative expense (\$/Boe) ⁽¹⁾	3.55	3.28	3.14	4.23
EBITDAX (in thousands) ⁽²⁾	244,950	108,659	426,738	199,655
Net income (loss) (in thousands) ⁽³⁾	127,307	(142,498)	215,278	(88,684)
Diluted net income (loss) per share	0.75	(0.87)	1.27	(0.55)
Pro forma net income (in thousands) ⁽⁴⁾		44,200		77,565
Pro forma diluted net income per share ⁽⁴⁾		0.27		0.48

- (1) Oil sales volumes were 16 MBbls more than oil production for the three months ended June 30, 2008 and 31 MBbls less than oil production for the three months ended June 30, 2007. For the six months ended June 30, 2008 oil sales volumes were 35 MBbls more than oil production and 47 MBbls less than oil production for the six months ended June 30, 2007. Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.
- (2) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains and losses and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). A reconciliation of net income to EBITDAX is provided in Managements Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures.
- (3) Prior to the public offering, we were a subchapter S corporation and income taxes were payable by our shareholders. In connection with the public offering, we converted to a subchapter C corporation and recorded a charge to earnings in the second quarter of 2007 of \$198.4 million to recognize deferred taxes relating to the timing differences that existed at May 14, 2007, the date we converted to a subchapter C corporation.
- (4) Pro forma adjustments are reflected to provide for income taxes in accordance with SFAS No. 109 as if we had been a subchapter C corporation for all periods presented. A statutory Federal tax rate of 35% and effective state tax rate of 3% (net of Federal income tax effects) were used for the pro forma enacted tax rate for 2007.

Table of Contents**Three months ended June 30, 2008 compared to the three months ended June 30, 2007**

Results of Operations

The following table presents selected financial and operating information for each of the periods indicated below:

(in thousands, except price data)	Three months ended June 30,	
	2008	2007
Oil and natural gas sales	\$ 297,619	\$ 140,046
Derivatives	(3,358)	
Total revenues	303,434	145,326
Operating costs and expenses	98,205	71,192
Other expense	2,617	2,843
Net income, before income taxes	202,612	71,291
Provision for income taxes	75,305	213,789
Net income (loss)	\$ 127,307	\$ (142,498)
Production Volumes:		
Oil (MBbl)	2,195	2,154
Natural gas (MMcf)	4,098	2,695
Oil equivalents (MBoe)	2,878	2,603
Sales Volumes:		
Oil (MBbl)	2,211	2,123
Natural gas (MMcf)	4,098	2,695
Oil equivalents (MBoe)	2,894	2,572
Average Prices: ⁽¹⁾		
Oil (\$/Bbl)	\$ 118.28	\$ 58.25
Natural gas (\$/Mcf)	\$ 8.82	\$ 6.07
Oil equivalents (\$/Boe)	\$ 102.86	\$ 54.44

⁽¹⁾ Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

Production

The following tables reflect our production by product and region for the periods presented.

	Three months ended June 30,		2007		Volume Increase	Percent Increase
	2008		2007			
	Volume	Percent	Volume	Percent		
Oil (MBbl)	2,195	76%	2,154	83%	41	2%
Natural Gas (MMcf)	4,098	24%	2,695	17%	1,403	52%
Total (MBoe)	2,878	100%	2,603	100%	275	11%

	Three months ended June 30,		2007		Volume Increase	Percent Increase
	2008		2007			
	MBoe	Percent	MBoe	Percent		
Rocky Mountain	2,228	77%	2,117	81%	111	5%
Mid-Continent	595	21%	446	17%	149	33%
Gulf Coast	55	2%	40	2%	15	38%

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

Total (MBoe)	2,878	100%	2,603	100%	275	11%
--------------	-------	------	-------	------	-----	-----

Table of Contents

Oil production volumes increased 2% during the three months ended June 30, 2008 in comparison to the three months ended June 30, 2007. Production increases in the Rockies Other area contributed incremental volumes in excess of 2007 levels of 60 MBbls primarily as a result of acquisitions and the Mid-Continent area contributed 25 MBbls of incremental production. These increases and increases in the North Dakota Bakken area were largely offset by decreases in production in the Montana Bakken area as a result of natural declines. The Red River Units production was negatively affected by a late winter storm that struck South Dakota in the first week of May, cutting electrical power to significant parts of the Units for most of that month. Continental estimates that the power outage reduced production in the Units and in the Other Rockies segment by an aggregate of approximately 500 barrels per day for the quarter. Gas volumes increased 1,403 MMcf, or 52% during the three months ended June 30, 2008 compared to the same time period in 2007. The majority of the gas increase, 840 MMcf, was from the results of our exploration efforts and successful drilling in the Arkoma Woodford shale play. The Rocky Mountain region gas production was up 661 MMcf for the three months ended June 30, 2008 compared to the same time period in 2007 due to additional gas being sold through the Hiland Partners Badlands plant which became operational in late August 2007.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the three months ended June 30, 2008 were \$297.6 million, a 113% increase from sales of \$140.0 million for the comparable period in 2007. Our sales volumes increased 321 MBoe or 12% over the 2007 volumes due to the continuing success of our enhanced oil recovery and drilling programs and acquisitions. Our realized price per Boe increased 89%, or \$48.42 to \$102.86 for the three months ended June 30, 2008 from \$54.44 for the three months ended June 30, 2007. During 2008, the differential between NYMEX calendar month average crude oil prices and our realized crude oil prices narrowed. The differential per barrel for the three months ended June 30, 2008 was \$5.75 compared to \$6.74 for the comparable period in 2007. Crude oil differentials are better during 2008 due to enhanced transportation capacity and efforts by us to move crude oil to more favorable markets.

Derivatives. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we received a fixed-price of \$72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil future contract settlement prices for such month. Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of operations. These contracts expired April 2008 and during the three months ended June 30, 2008, we had recognized losses on derivatives of \$3.4 million.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of reclaimed oil. We sold high-pressure air from our Red River units to a third party and recorded revenues of \$0.8 million for the three months ended June 30, 2008 and 2007. Prices for reclaimed oil sold from our central treating unit were \$61.10 per barrel higher for the three months ended June 30, 2008 than the comparable 2007 period which increased reclaimed oil income by \$3.6 million contributing to an overall increase in oil and gas service operations revenue of \$3.9 million for the three months ended June 30, 2008. Associated oil and natural gas service operations expenses increased \$3.3 million to \$6.5 million during the three months ended June 30, 2008 due mainly to an increase of \$57.38 per barrel in the costs of purchasing and treating oil for resale compared to the same period in 2007.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased \$5.3 million, or 24% during the three months ended June 30, 2008 to \$27.0 million from \$21.7 million during the three months ended June 30, 2007. Our costs increased as a result of new wells being drilled coupled with workovers and repairs on existing wells and acquisitions. Our workover activity is typically higher in the summer months as weather conditions in the northern Rockies moderate. Additionally, we have experienced increases in energy, chemical and service costs. During the three months ended June 30, 2008, we participated in the completion of 77 gross (32.7 net) wells. Production expense per Boe increased to \$9.32 per Boe for the three months ended June 30, 2008 from \$8.42 per Boe for the three months ended June 30, 2007.

Production taxes increased \$10.3 million, or 138% during the three months ended June 30, 2008 compared to the three months ended June 30, 2007 as a result of higher revenues from increased sales prices and volumes and the expiration of various tax incentives. The majority of the production tax increase was in the Rocky Mountain region due to significantly higher oil and natural gas prices and an increase of 130 MBoe sold in the three months ended June 30, 2008 compared to the

Table of Contents

three months ended June 30, 2007. Production tax as a percentage of oil and natural gas sales was 5.95% for the three months ended June 30, 2008 compared to 5.31% for the three months ended June 30, 2007. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, North Dakota and Oklahoma new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rates. Our overall rate is expected to increase as production tax incentives we currently receive for horizontal wells reach the end of their incentive period.

On a unit of sales basis, production expense and production taxes were as follows:

(\$/Boe)	Three months ended June 30,		Percent Increase
	2008	2007	
Production expense	\$ 9.32	\$ 8.42	11%
Production tax	6.12	2.89	112%
Production expense and tax	\$ 15.44	\$ 11.31	37%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased \$4.1 million during the three months ended June 30, 2008 to \$5.7 million due primarily to an increase in seismic expense of \$3.1 million and an increase in dry hole expense of \$0.9 million.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A increased \$4.7 million in 2008 primarily due to an increase in oil and gas DD&A of \$4.6 million as a result of increased production and additional properties being added through our drilling program and acquisitions. The following table shows the components of our DD&A rate for the three months ended June 30, 2008 and 2007.

(\$/Boe)	Three months ended June 30,	
	2008	2007
Oil and gas	\$ 9.33	\$ 8.69
Other equipment	0.20	0.18
Asset retirement obligation accretion	0.17	0.19

Depreciation, depletion, amortization and accretion	\$ 9.70	\$ 9.06
---	---------	---------

The increase in the oil and gas DD&A rate reflects the additional costs incurred to develop proved undeveloped reserves and the higher costs of drilling and completing wells. Our DD&A rate may continue to increase due to drilling for higher cost reserves.

Property Impairments. Property impairments decreased during the three months ended June 30, 2008 by \$2.8 million to \$3.2 million during the three months ended June 30, 2007 primarily due to a reduction in impairment of developed properties. Impairment of non-producing properties decreased \$0.4 million during the three months ended June 30, 2008 to \$2.7 million. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

General and Administrative Expense. General and administrative expense increased \$1.9 million to \$10.3 million during the three months ended June 30, 2008. General and administrative expense includes non-cash charges for stock-based compensation of \$2.5 million and \$3.1 million for the three months ended June 30, 2008 and 2007, respectively. Stock compensation expense was higher in 2007 due to the increase in value of the stock as we approached our initial public offering. Until our initial public offering in May 2007, the outstanding options and restricted stock were accounted for as liability awards and their value fluctuated with the value of the underlying stock. General and administrative expenses excluding equity compensation increased \$2.4 million for the three months ended June 30, 2008 compared to the three months ended June 30, 2007. In June 2008, the Company made a \$1.0 million donation to take advantage of private and state matching funds that will result in a total donation of \$4.0 million to support a petroleum engineering program at Oklahoma State University. The remaining increase was primarily related to personnel costs. On a volumetric basis, general and administrative expense was \$3.55 per Boe for the three months ended June 30, 2008 compared to \$3.28 per Boe for the three months ended June 30, 2007.

Table of Contents

Gain on Sale of Assets. Gains on miscellaneous asset sales for the three months ended June 30, 2008 was approximately \$133,000 compared to \$338,000 for the three months ended June 30, 2007.

Interest Expense. Interest expense decreased 16%, or \$0.6 million for the three months ended June 30, 2008 compared to the three months ended June 30, 2007, due to a lower weighted average interest rate on our credit facility of 4.40% for the three months ended June 30, 2008 compared to 6.50% for the three months ended June 30, 2007. Our weighted average interest rate has fallen in 2008 as LIBOR rates have declined. Our average outstanding debt balance on our credit facility increased to \$241.3 million for the three months ended June 30, 2008 compared to \$196.3 million for the three months ended June 30, 2007. At July 31, 2008, our outstanding balance was \$214.0 million and our weighted average interest rate was 3.82%.

Income Taxes. Income taxes for the three months ended June 30, 2008 were \$75.3 million for an effective tax rate of 37.2%. See *Note 6. Income Taxes* in Notes to Unaudited Condensed Consolidated Financial Statements for more information.

Six months ended June 30, 2008 compared to the six months ended June 30, 2007

Results of Operations

The following table presents selected financial and operating information for each of the periods indicated below:

(in thousands, except price data)	For the six months ended June 30,	
	2008	2007
Oil and natural gas sales	\$ 523,044	\$ 256,030
Derivatives	(7,966)	
Total revenues	531,085	266,449
Operating costs and expenses	184,163	135,153
Other expense	5,729	6,191
Net income, before income taxes	341,193	125,105
Provision for income taxes	125,915	213,789
Net income (loss)	\$ 215,278	\$ (88,684)
Production Volumes:		
Oil (MBbl)	4,383	4,234
Natural gas (MMcf)	7,480	5,290
Oil equivalents (MBoe)	5,629	5,116
Sales Volumes:		
Oil (MBbl)	4,418	4,187
Natural gas (MMcf)	7,480	5,290
Oil equivalents (MBoe)	5,665	5,068
Average Prices: ⁽¹⁾		
Oil (\$/Bbl)	\$ 104.43	\$ 53.44
Natural gas (\$/Mcf)	\$ 8.25	\$ 6.11
Oil equivalents (\$/Boe)	\$ 92.34	\$ 50.52

(1) Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

Table of Contents**Production**

The following tables reflect our production by product and region for the periods presented.

	Six Months Ended June 30, 2008		2007		Volume increase	Percent increase
	Volume	Percent	Volume	Percent		
Oil (MBbl)	4,383	78%	4,234	83%	149	4%
Natural Gas (MMcf)	7,480	22%	5,290	17%	2,190	41%
Total (MBoe)	5,629	100%	5,116	100%	513	10%

	Six Months Ended June 30, 2008		2007		Volume Increase	Percent Increase
	MBoe	Percent	MBoe	Percent		
Rocky Mountain	4,402	78%	4,137	81%	265	6%
Mid-Continent	1,117	20%	874	17%	243	28%
Gulf Coast	110	2%	105	2%	5	5%

Total (MBoe) 5,629 100% 5,116 100% 513 10%

Oil production volumes increased 4% during the six months ended June 30, 2008 in comparison to the six months ended June 30, 2007.

Production increases in the Red River units contributed incremental volumes in excess of 2007 levels of 56 MBbls and the Rockies Other area contributed 86 MBbls of incremental production. Favorable results from our enhanced recovery program, increased density drilling and acquisitions have been the primary contributors to production growth in the Rocky Mountain area. Gas volumes increased 2.2 Bcf, or 41% during the six months ended June 30, 2008 compared to the same time period in 2007. The majority of the gas increase, 1.3 Bcf, was from the Mid-Continent region due to the results of our exploration efforts and successful drilling in the Arkoma Woodford shale play. The Rocky Mountain region gas production was up 988 MMcf for the six months ended June 30, 2008 compared to the same time period in 2007 due to additional gas being sold through the Hiland Partners Badlands plant which became operational in late August 2007. Since that time, we have sold 1.6 Bcf of gas from the Red River units through the Badlands plant.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the six months ended June 30, 2008 were \$523.0 million, a 104% increase from sales of \$256.0 million for the comparable period in 2007. Our sales volumes increased 596 MBoe or 12% over the 2007 volumes due to the continuing success of our enhanced oil recovery and drilling programs and acquisitions. Our realized price per Boe increased 83%, or \$41.82, to \$92.34 for the six months ended June 30, 2008 from \$50.52 for the six months ended June 30, 2007. During 2008, the differential between NYMEX calendar month average crude oil prices and our realized crude oil prices narrowed. The differential per barrel for the six months ended June 30, 2008 was \$6.58 compared to \$8.29 for the comparable period in 2007. Crude oil differentials have improved during 2008 due to enhanced transportation capacity and efforts by us to move crude oil to more favorable markets.

Derivatives. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we received a fixed-price of \$72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil future contract settlement prices for such month. Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of operations. These contracts expired in April 2008 and during the six months ended June 30, 2008, we had recognized losses on derivatives of \$8.0 million.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of reclaimed oil. We sold high-pressure air from our Red River units to a third party and recorded revenues of \$1.5 million for the six months ended June 30, 2008 and \$1.6 million for the six months ended June 30, 2007. Prices for reclaimed oil sold from our central treating unit were \$51.49 per barrel higher for the six months ended June 30, 2008 than the comparable 2007 period which increased reclaimed oil income by \$5.2 million contributing to an overall increase in oil and gas service operations revenue of \$5.6 million for the six months ended June 30, 2008.

Table of Contents

Associated oil and natural gas service operations expenses increased \$4.3 million to \$10.7 million during the six months ended June 30, 2008 from \$6.4 million during the six months ended June 30, 2007 due mainly to an increase of \$48.15 per barrel in the costs of purchasing and treating oil for resale compared to the same period in 2007.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased \$12.4 million, or 33%, during the six months ended June 30, 2008 to \$50.0 million from \$37.6 million during the six months ended June 30, 2007. Our costs increased as a result of new wells being drilled coupled with workovers and repairs on existing wells and acquisitions. Additionally, we have experienced increases in energy, chemical and service costs. During the six months ended June 30, 2008, we participated in the completion of 131 gross (61.4 net) wells. Production expense per Boe increased to \$8.83 per Boe for the six months ended June 30, 2008 from \$7.43 per Boe for the six months ended June 30, 2007.

Production taxes increased \$16.9 million, or 124% during the six months ended June 30, 2008 compared to the six months ended June 30, 2007 as a result of higher revenues from increased sales prices and volumes and the expiration of various tax incentives. The majority of the production tax increase was in the Rocky Mountain region due to significantly higher oil and natural gas prices and an increase of 225 MBoe sold in the six months ended June 30, 2008 compared to the six months ended June 30, 2007. Production tax as a percentage of oil and natural gas sales was 5.83% for the six months ended June 30, 2008 compared to 5.31% for the six months ended June 30, 2007. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, North Dakota and Oklahoma new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rates. Our overall rate is expected to increase as production tax incentives we currently receive for horizontal wells reach the end of their incentive period.

On a unit of sales basis, production expense and production taxes were as follows:

(\$/Boe)	Six Months Ended June 30,		Percent Increase
	2008	2007	
Production expense	\$ 8.83	\$ 7.43	19%
Production tax	5.38	2.68	101%
Production expense and tax	\$ 14.21	\$ 10.11	41%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased \$7.1 million during the six months ended June 30, 2008 to \$11.0 million due primarily to an increase in seismic expense of \$6.4 million.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A increased \$13.0 million in 2008 primarily due to an increase in oil and gas DD&A of \$12.8 million as a result of increased production and additional properties being added through our drilling program and acquisitions. The following table shows the components of our DD&A rate.

(\$/Boe)	Six Months Ended June 30,	
	2008	2007
Oil and gas	\$ 9.64	\$ 8.26
Other equipment	0.19	0.18
Asset retirement obligation accretion	0.18	0.19

Depreciation, depletion, amortization and accretion \$ 10.01 \$ 8.63

The increase in the oil and gas DD&A rate reflects the additional costs incurred to develop proved undeveloped reserves and the higher costs of drilling and completing wells. Our DD&A rate may continue to increase due to drilling for higher cost reserves.

Property Impairments. Property impairments decreased during the six months ended June 30, 2008 by \$1.2 million to \$7.7 million primarily due to a reduction in impairments of developed properties. Impairment of non-producing properties decreased \$0.2 million during the six months ended June 30, 2008 to \$5.9 million. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

General and Administrative Expense. General and administrative expense decreased \$3.6 million to \$17.8 million during the six months ended June 30, 2008 from \$21.4 million during the same period in 2007. General and administrative

Table of Contents

expense includes non-cash charges for stock-based compensation of \$3.9 million and \$10.9 million for the six months ended June 30, 2008 and 2007, respectively. Stock compensation expense was higher in 2007 due to the increase in value of the stock as we approached our initial public offering. Until our initial public offering in May 2007, the outstanding options and restricted stock were accounted for as liability awards and their value fluctuated with the value of the underlying stock. General and administrative expenses excluding equity compensation increased \$3.4 million for the six months ended June 30, 2008 compared to the six months ended June 30, 2007. In June 2008, the Company made a \$1.0 million donation to take advantage of private and state matching funds that will result in a total donation of \$4.0 million to support a petroleum engineering program at Oklahoma State University. The remaining increase was primarily related to personnel costs. On a volumetric basis, general and administrative expense was \$3.14 per Boe for the six months ended June 30, 2008 compared to \$4.23 per Boe for the six months ended June 30, 2007.

Gain on Sale of Assets. Gains on miscellaneous asset sales for the six months ended June 30, 2008 was approximately \$212,000 compared to \$400,000 for the six months ended June 30, 2007.

Interest Expense. Interest expense decreased 11%, or \$0.8 million, for the six months ended June 30, 2008 compared to the six months ended June 30, 2007, due to a lower weighted average interest rate on our credit facility of 5.04% for the six months ended June 30, 2008 compared to 6.54% for the six months ended June 30, 2007. Our weighted average interest rate has fallen in 2008 as LIBOR rates have declined. Our average outstanding debt balance on our credit facility increased to \$224.5 million for the six months ended June 30, 2008 compared to \$198.6 million for the six months ended June 30, 2007. At July 31, 2008, our outstanding balance was \$214.0 million and our weighted average interest was 3.82%.

Income Taxes. Income taxes for the six months ended June 30, 2008 were \$125.9 million for an effective tax rate of 36.9%. See *Note 6. Income Taxes* in Notes to Unaudited Condensed Consolidated Financial Statements for more information.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facility. We believe that funds from operating cash flows and the bank credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months. We intend to fund our longer term cash requirements beyond 12 months through operating cash flows, commercial bank borrowings and access to equity and debt capital markets. Although our longer term needs may be impacted by factors such as proved reserve acquisitions, declines in oil and natural gas prices, drilling results, ability to obtain needed capital on satisfactory terms, and other risks which could negatively impact production and our results of operations, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements.

At June 30, 2008 and December 31, 2007, we had cash and cash equivalents of \$13.2 million and \$8.8 million, respectively. At June 30, 2008, our available borrowing capacity on our credit facility was \$180.0 million. The amount borrowed under the credit facility at July 31, 2008 was \$214.0 million and we have unused commitments of \$186.0 million. During the second quarter of 2008, in connection with our semiannual borrowing base redetermination, our borrowing base was raised to \$1.0 billion. Our commitment level remains at \$400.0 million. While the borrowing base is set at \$1.0 billion by our banks based on their valuation of the underlying reserves, we could not borrow more than the maximum facility amount of \$750.0 million without amending the agreement.

Cash Flow From Operating Activities

Our net cash provided by our operating activities for the six months ended June 30, 2008, was \$298.0 million, an increase of \$134.5 million from \$163.5 million provided by our operating activities during the comparable 2007 period. The increase in operating cash flows was mainly due to increases in revenue reflecting increased production volumes and product prices partially offset by higher operating costs.

Cash Flow From Investing Activities

During the six months ended June 30, 2008 and 2007 we had cash flows used in investing activities (excluding asset sales) of \$350.0 million and \$235.1 million, respectively in our capital program, inclusive of dry hole and seismic costs. The increase in our capital program was mainly due to increased drilling in our Rocky Mountain region and in our Arkoma Woodford shale play.

Cash Flow From Financing Activities

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

Net cash provided by financing activities of \$55.2 million for the six months ended June 30, 2008 was mainly the result of amounts borrowed under our credit facility to fund capital expenditures, including acquisitions. Net cash provided by financing activities was \$69.6 million for the six months ended June 30, 2007 and was mainly the result of proceeds of our initial public offering net of amounts used to pay cash dividends.

Table of Contents

Capital Expenditures

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas such as the purchase of producing properties in the Williston Basin for \$56.1 million in January 2008. Acquisition expenditures are not budgeted. Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. During the first six months of 2008, we participated in the completion of 131 gross (61.4 net) wells and invested a total of \$327.0 million including \$267.5 million in drilling and capital facilities and \$56.0 million for undeveloped acreage.

Since late 2007, our cash flow outlook has increased significantly and as a result in April 2008, the Board of Directors approved an increase in our drilling, land and seismic capital expenditures budget from \$616.0 million to \$783.0 million. In addition to the revised capital budget, we have invested \$71.0 million for acquisitions through June 30, 2008. In July 2008, the Board of Directors increased the land budget by \$100 million to \$178 million.

Although we can not provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance, cash flows from operations and borrowings available under our credit facility will be sufficient to satisfy our 2008 capital budget.

Recent Accounting Pronouncements

In February 2008, the FASB issued FASB Staff Position FAS 157-2, *Effective Date of FASB Statement No. 157*, which provides a one year delay of the effective date of FAS 157 to January 1, 2009 for us for non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The impact of adoption related to the non-financial assets and liabilities will depend on our assets and liabilities at the time they are required to be measured at fair value.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51* (SFAS 160). SFAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS 160 will change the accounting and reporting for minority interests, which will be re-characterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for our fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. Early adoption is prohibited for both standards. The adoption of SFAS 141(R) and SFAS 160 is not expected to have a material impact on our consolidated financial position or results of operations.

In March 2008, the FASB issued FAS 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*, which amends and expands the disclosure requirements of FAS 133 to require qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement will be effective for us beginning in fiscal 2009. The adoption of this statement will change the disclosures related to derivative instruments held by us.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162), which identifies the sources of accounting principles and the framework for selecting the principles to be used in preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS No. 162 is effective sixty days following the SEC's approval of PCAOB amendments to AU Section 411, *The Meaning of Present fairly in conformity with generally accepted accounting principles*. SFAS 162 is not expected to have a material impact on the Company's consolidated financial position or results of operations.

Table of Contents*Contractual Commitments*

There have been no material changes in our contractual obligations and commitments from those disclosed in our Form 10-K for the year ended December 31, 2007.

Critical Accounting Policies

There has been no change in our critical accounting policies from those disclosed in our Form 10-K for the year ended December 31, 2007.

Disclosure Regarding Forward-Looking Statements

This report includes forward-looking information that is subject to a number of risks and uncertainties, many of which are beyond our control. All information, other than historical facts included in this report, regarding our strategy, future operations, drilling plans, estimated reserves, future production, estimated capital expenditures, projected costs, the potential of drilling prospects and other plans and objectives of management are forward-looking information. All forward-looking statements speak only as of the date of this report. Although we believe that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Actual results may differ materially from those anticipated due to many factors, including oil and natural gas prices, industry conditions, drilling results, uncertainties in estimating reserves, uncertainties in estimating future production from enhanced recovery operations, availability of drilling rigs and other services, availability of crude oil and natural gas transportation capacity, availability of capital resources and other factors listed in reports we have filed or may file with the Securities and Exchange Commission.

Non-GAAP Financial Measures

EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains and losses, and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company's operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. The credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. The following table is a reconciliation of our net income to EBITDAX.

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Net income (loss)	\$ 127,307	\$ (142,498)	\$ 215,278	\$ (88,684)
Interest expense	2,865	3,427	6,276	7,080
Provision for income taxes	75,305	213,789	125,915	213,789
Depreciation, depletion, amortization and accretion	28,062	23,330	56,708	43,738
Property impairments	3,153	5,923	7,673	8,893
Exploration expense	5,731	1,602	10,993	3,906
Equity compensation	2,527	3,086	3,895	10,933
EBITDAX	\$ 244,950	\$ 108,659	\$ 426,738	\$ 199,655

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk
General

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

We are exposed to a variety of market risks, commodity price risk and interest rate risk. We address these risks through a program of risk management which may include the use of derivative instruments.

Table of Contents

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and gas production, which we market to energy marketing companies, refineries and affiliates. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's credit worthiness. Although we have not generally required our counterparties to provide collateral to support trade receivables owed to us, we routinely require prepayment of working interest holders' proportionate share of drilling costs. A liability is recorded for such prepayments and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk.

Commodity Price Risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged crude oil and natural gas prices in the past, through the utilization of derivatives, including zero-cost collars and fixed price contracts. In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008. During each month of the contract, we received a fixed-price of \$72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of operations. During the six months ended June 30, 2008, we had recognized losses on derivatives of \$8.0 million. These contracts expired in April 2008 and we currently have no hedges 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. We are exposed to changes in interest rates as a result of our credit facility. We had total indebtedness of \$220.0 million outstanding under our credit facility at June 30, 2008. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately \$2.2 million per year. Our long-term debt matures in 2011 and the weighted-average interest rate at June 30, 2008 is 3.93%.

ITEM 4. Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rule 240.13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in reports that it files or submits under the Exchange Act are accumulated and communicated to the issuer's management, including its Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, as appropriate to make timely decisions regarding required disclosures. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer have concluded that our current disclosure controls and procedures are effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms.

There have been no changes in our internal controls over financial reporting during the quarter ended June 30, 2008 that have materially affected or is reasonably likely to materially effect our internal controls over financial reporting.

Table of Contents**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 1A. Risk Factors

There has been no change in our risk factors from those disclosed in our Form 10-K for the year ended December 31, 2007.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) Not applicable.

(b) Not applicable.

(c) Share repurchases.

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number of shares that may yet be purchased under the plans or program
April 1, 2008 to April 30, 2008	4,369	\$ 32.87		
May 1, 2008 to May 31, 2008	41,090	\$ 50.70		
June 1, 2008 to June 30, 2008	24,874	\$ 65.37		

Total	70,333	\$ 54.78		
-------	--------	----------	--	--

All shares purchased above represent shares issued pursuant to stock option exercises or restricted stock grants that were forfeited to cover taxes required to be withheld. The Company paid the amounts above to the Internal Revenue Service for the required withholding. See *Note 8. Stock Compensation* in Notes to Unaudited Condensed Consolidated Financial Statements.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Submission of Matters to a Vote of Security Holders

The Company held its Annual Meeting of Shareholders on May 27, 2008, for the purpose of electing one Director of the Company for a three year term and to ratify the appointment of Grant Thornton LLP to serve as the Company's independent registered public accounting firm for 2008. Holders of 165,062,700 shares (97.6% of total outstanding shares) voted in total.

Edgar Filing: CONTINENTAL RESOURCES INC - Form 10-Q

Holders of 164,886,260 shares voted for H. R. Sanders to serve as a Director of the Company for a period of three years, 176,440 shares withheld authority.

Holders of 165,022,184 shares voted for the proposal to ratify the appointment of Grant Thornton LLP to serve as the Company's independent registered public accounting firm for 2008, 24,344 shares voted against and 16,172 shares abstained.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

See the Exhibit Index accompanying this report.

Table of Contents

SIGNATURE

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

Continental Resources, Inc.

Date: August 8, 2008

By: /s/ John D. Hart
John D. Hart
Vice President, Chief Financial Officer and Treasurer

Table of Contents

INDEX TO EXHIBITS

- 3.1 Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
- 3.2 Second Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.2 to the Company's Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
- 4.1 Registration Rights Agreement filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed May 22, 2007 and incorporated herein by reference.
- 4.2 Specimen Common Stock Certificate filed as Exhibit 4.1 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.1 Sixth Amended and Restated Credit Agreement among Union Bank of California, N.A., Guaranty Bank, FSB, Fortis Capital Corp., The Royal Bank of Scotland plc, other financial institutions and banks and Continental Resources, Inc. dated April 12, 2006 filed as Exhibit 10.1 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.2 Omnibus Agreement among Continental Resources, Inc., Hiland Partners, LLC, Harold Hamm, Hiland Partners GP, LLC, Continental Gas Holdings, Inc. and Hiland Partners, LP effective as of the closing of Hiland Partners, LP's initial public offering of common units (incorporated by reference to Exhibit 10.10 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
- 10.3 Compression Services Agreement among Hiland Partners, LP and Continental Resources, Inc. effective as of January 28, 2005 (incorporated by reference to Exhibit 10.3 to the Annual Report on Form 10-K of Hiland Partners, LP filed on March 30, 2005, Commission File No. 000-51120).
- 10.4 Gas Purchase Contract between Continental Resources, Inc. and Hiland Partners, LP dated November 8, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Hiland Partners, LP filed on November 10, 2005, Commission File No. 000-51120).
- 10.5 Strategic Customer Relationship Agreement among Complete Energy Services, Inc., CES Mid-Continent Hamm, Inc. and Continental Resources, Inc. dated October 14, 2004 (incorporated by reference to Exhibit 10.12 to the Registration Statement on Form S-1 of Complete Production Services, Inc. filed on November 15, 2005, Commission File No. 333-128750).
- 10.6 Continental Resources, Inc. 2000 Stock Option Plan filed as Exhibit 10.6 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.7 First Amendment to Continental Resources, Inc. 2000 Stock Option Plan filed as Exhibit 10.7 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.8 Form of Incentive Stock Option Agreement filed as Exhibit 10.8 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.9 Amended and Restated Continental Resources, Inc. 2005 Long-Term Incentive Plan effective as of April 3, 2006 filed as Exhibit 10.9 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.10 Form of Restricted Stock Award Agreement filed as Exhibit 10.10 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.11 Amended and Restated Employment Agreement between Continental Resources, Inc. and Mark E. Monroe dated April 3, 2006 filed as Exhibit 10.11 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.12 Form of Indemnification Agreement between Continental Resources, Inc. and each of the directors and executive officers thereof filed as Exhibit 10.12 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.

Table of Contents

- 10.13 Membership Interest Assignment Agreement by and between Continental Resources, Inc., the Harold Hamm Revocable Inter Vivos Trust, the Harold Hamm HJ Trust and the Harold Hamm DST Trust dated March 30, 2006 filed as Exhibit 10.13 to the Company's registration statement on Form S-1 (file No. 333-132257) filed April 14, 2006 and incorporated herein by reference.
- 10.14 Crude oil gathering agreement between Banner Pipeline Company, LLC, a wholly owned subsidiary of Continental Resources, Inc. and Banner Transportation Company dated July 11, 2007 filed as Exhibit 99.1 to the Company's Current Report on Form 8-K filed July 11, 2007 and incorporated herein by reference.
- 31.1 * Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 7241)
- 31.2 * Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(18 U.S.C. Section 7241)
- 32 * Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350)

* Filed herewith