CONTINENTAL RESOURCES INC
Form 10-Q
November 09, 2007
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 September 30, 2007

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)

Oklahoma	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
302 N. Independence, Suite 1500, Enid, Oklahoma	**73701**

(Address of principal executive offices) **(Zip Code)**

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

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 x No ¨

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

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date. 168,049,246 common shares were outstanding on October 31, 2007.

Table of Contents

CONTINENTAL RESOURCES, INC.

FORM 10-Q

Quarter Ended September 30, 2007

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

Table of Contents

PART I. Financial Information

ITEM 1. Financial Statements

The following condensed balance sheet as of December 31, 2006, which has been derived from audited financial statements, and the unaudited interim condensed consolidated financial statements of Continental Resources, Inc. and Subsidiary have been prepared by the Company in accordance with the accounting policies stated in the Historical Consolidated Financial Statements contained in the Company s S-1/A filed May 10, 2007 and are based in part on estimates. It is suggested that these condensed financial statements be read in conjunction with the financial statements and notes thereto included in such S-1/A filing. 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 (US GAAP) have been included in these unaudited interim condensed consolidated financial statements. The following unaudited condensed consolidated financial statements have also been prepared pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and note disclosures normally included in annual financial statements prepared in accordance with US GAAP have been condensed or omitted pursuant to those rules and regulations, although the Company believes that the disclosures made are adequate to make the information not misleading.

The Company filed its Historical Consolidated Financial Statements as part of its S-1/A filed with the Securities and Exchange Commission on May 10, 2007. As described in more detail in *Notes to Consolidated Financial Statements Note 1. Organization and Summary of Significant Accounting Policies Restatement,* the Company restated its consolidated balance sheet as of December 31, 2006, its consolidated statements of income, changes in shareholders equity and cash flows and for the year ended December 31, 2006. The restatement corrected the application of Statement of Financial Accounting Standards (SFAS) No. 123(R) which requires that after the Company became a public entity, as defined in SFAS 123(R), (March 7, 2006, the date on which the Company first filed a registration statement) the amount of stock-based compensation expense related to restricted stock and stock options should be adjusted to reflect fair value. For calculating stock-based compensation expense for financial reporting purposes and for the nine months ended September 30, 2006, the Company adjusted the fair value for restricted stock and stock options. As a result, the consolidated financial statements of the Company for the nine months ended September 30, 2006, have been restated from the amounts previously reported to reflect the changes in stock-based compensation expense. The change resulted in net income being reduced by $4.8 million for the nine months ended September 30, 2006. See *Notes to Condensed Consolidated Financial Statements Note 2. Basis of Presentation and Significant Accounting Policies Restatement* for a complete discussion of the effects of the restatement on the Company s financial statements for the nine months ended September 30, 2006.

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. See *Notes to Unaudited Condensed Consolidated Financial Statements Note 2. Basis of Presentation and Significant Accounting Policies Shareholders Equity, Income Taxes* and *Pro forma information (unaudited)* for a complete discussion of the accounting for the various transactions resulting from the initial public offering and of the pro forma information presented.

Table of Contents

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Balance Sheets

	September 30, 2007 (Unaudited)	December 31, 2006
	(in thousands, except share amounts)	
Current assets:		
Cash and cash equivalents	$ 5,483	$ 7,018
Receivables:		
Oil and natural gas sales	88,883	55,037
Affiliated parties	10,090	7,698
Joint interest and other, net	45,919	26,351
Inventories	13,119	7,831
Deferred and prepaid taxes	17,372	
Prepaid expenses and other	874	1,046
Total current assets	181,740	104,981
Net property and equipment, based on successful efforts method of accounting	1,072,245	751,747
Debt issuance costs, net	1,808	2,201
Total assets	$ 1,255,793	$ 858,929
Liabilities and shareholders equity:		
Current liabilities:		
Accounts payable trade	$ 130,179	$ 100,414
Accounts payable to affiliated parties	14,491	13,727
Accrued liabilities and other	38,109	43,230
Revenues and royalties payable	53,375	28,738
Current portion of asset retirement obligation	2,585	2,528
Total current liabilities	238,739	188,637
Long-term debt	156,500	140,000
Other noncurrent liabilities:		
Deferred tax liability	253,869	
Asset retirement obligation, net of current portion	41,245	38,745
Other noncurrent liabilities	3,541	1,086
Total other noncurrent liabilities	298,655	39,831
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, $.01 par value: 500,000,000 shares authorized, 159,106,244 shares issued and outstanding at December 31, 2006; 168,094,555 shares issued and outstanding at September 30, 2007	1,681	144
Additional paid-in-capital	414,967	27,087
Retained earnings	145,116	463,255
Accumulated other comprehensive gain (loss), net of tax	135	(25)
Total shareholders equity	561,899	490,461
Total liabilities and shareholders equity	$ 1,255,793	$ 858,929

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 September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006 (as restated, see Note 2)
	(In thousands, except per share data)			
Revenues:				
Oil and natural gas sales	$ 159,987	$ 129,087	$ 400,781	$ 270,641
Oil and natural gas sales to affiliates	6,717	8,194	21,953	87,363
Loss on mark-to-market derivative instruments	(14,393)		(14,393)	
Oil and natural gas service operations	4,461	3,592	14,880	11,735
Total revenues	156,772	140,873	423,221	369,739
Operating costs and expenses:				
Production expense	16,014	12,349	44,629	33,487
Production expense to affiliates	4,547	3,505	13,572	12,673
Production tax	8,711	6,618	22,311	16,610
Exploration expense	2,758	4,018	6,664	9,085
Oil and natural gas service operations	2,414	1,863	8,767	6,644
Depreciation, depletion, amortization and accretion	23,568	18,395	67,306	46,376
Property impairments	4,099	1,347	12,992	9,080
General and administrative	6,231	2,420	27,654	24,571
Loss (gain) on sale of assets	62	(85)	(338)	(292)
Total operating costs and expenses	68,404	50,430	203,557	158,234
Income from operations	88,368	90,443	219,664	211,505
Other income (expense):				
Interest expense	(2,774)	(3,101)	(9,854)	(8,522)
Other	318	517	1,207	1,230
	(2,456)	(2,584)	(8,647)	(7,292)
Net income before income taxes	85,912	87,859	211,017	204,213
Provision (benefit) for income taxes	29,540	(132)	243,329	(132)
Net income (loss)	$ 56,372	$ 87,991	$ (32,312)	$ 204,345
Basic net income (loss) per share	$ 0.34	$ 0.56	$ (0.20)	$ 1.29
Diluted net income (loss) per share	0.33	0.55	(0.20)	1.28
Dividends per share		0.17	.33	0.55
Weighted average shares:				
Basic	167,232	158,106	162,869	158,058
Diluted	169,043	159,919	162,869	159,680
Pro forma:				
Net income before income taxes		$ 87,859	$ 211,017	$ 204,213
Pro forma provision for income taxes		33,386	80,186	77,601
Pro forma net income		$ 54,473	$ 130,831	$ 126,612

Pro forma basic net income per share	$ 0.34	$ 0.80	$ 0.80
Pro forma diluted net income per share	0.34	0.80	0.79
Pro forma weighted average shares:			
Basic	158,106	162,869	158,058
Diluted	159,919	164,546	159,680

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

5

Table of Contents

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Statements of Shareholders Equity

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income	Total shareholders Equity
			(in thousands, except share data)			
Balance, January 1, 2006	159,048,626	$ 144	$ 27,087	$ 297,461	$ 38	$ 324,730
Comprehensive income:						
Net income				253,088		253,088
Other comprehensive loss					(63)	(63)
Total comprehensive income						253,025
Stock options exercised	22,660					
Restricted stock:						
Issuance	200,772					
Repurchased and canceled	(23,309)					
Stock withheld for taxes	(37,356)					
Forfeited	(105,149)					
Cash dividends				(87,294)		(87,294)
Balance, December 31, 2006	159,106,244	144	27,087	463,255	(25)	490,461
Comprehensive income (loss):						
Net loss (unaudited)				(32,312)		(32,312)
Other comprehensive income, net of tax (unaudited)					160	160
Total comprehensive loss (unaudited)						(32,152)
Public offering of common stock (unaudited)	8,850,000	89	124,406			124,495
Reclass for stock split (unaudited)		1,447	(1,447)			
Adjust for undistributed earnings from conversion to C corporation (unaudited)			234,099	(234,099)		
Reclass stock compensation liability to equity (unaudited)			29,828			29,828
Stock based compensation (unaudited)			1,834			1,834
Stock options:						
Exercised (unaudited)	306,163	1	83			84
Repurchased and canceled (unaudited)	(195,597)		(792)			(792)
Restricted stock:						
Issued (unaudited)	77,484					
Repurchased and canceled (unaudited)	(8,104)		(25)			(25)
Forfeited (unaudited)	(41,635)		(106)			(106)
Dividends (unaudited)				(51,728)		(51,728)
Balance, September 30, 2007 (unaudited)	168,094,555	$ 1,681	$ 414,967	$ 145,116	$ 135	$ 561,899

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

	Nine months ended September 30, 2007	Nine months ended September 30, 2006 (as restated, see Note 2)
	(in thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (32,312)	$ 204,345
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	68,124	46,420
Property impairments	12,992	9,080
Change in derivative fair value	12,542	
Amortization of debt issuance costs and other	487	744
Gain on sale of assets	(338)	(292)
Dry hole costs	2,293	5,142
Equity compensation	12,097	9,733
Provision for income tax	243,329	
Changes in assets and liabilities:		
Accounts receivable	(55,806)	(17,866)
Inventories	(5,288)	(3,499)
Prepaid expenses and other	(6,654)	511
Accounts payable	(1,664)	26,259
Revenues and royalties payable	24,637	4,099
Accrued liabilities and other	3,579	4,147
Other noncurrent liabilities	338	176
Net cash provided by operating activities	278,356	288,999
Cash flows from investing activities:		
Exploration and development	(366,013)	(209,587)
Purchase of other property and equipment	(3,865)	(5,196)
Purchase of oil and gas properties	(146)	(6,505)
Proceeds from sale of assets	2,091	1,852
Net cash used in investing activities	(367,933)	(219,436)
Cash flows from financing activities:		
Line of credit and other borrowings	239,500	216,000
Repayment of line of credit and other borrowings	(223,000)	(199,000)
Proceeds from initial public offering, net	124,495	
Exercise and repurchase of equity grants	(1,336)	
Dividends to shareholders	(51,835)	(87,075)
Exercise of options	103	
Debt issuance costs	(45)	(1,087)
Net cash provided by (used in) financing activities	87,882	(71,162)
Effect of exchange rate changes on cash and cash equivalents	160	41
Net change in cash and cash equivalents	(1,535)	(1,558)
Cash and cash equivalents at beginning of period	7,018	6,014
Cash and cash equivalents at end of period	$ 5,483	$ 4,456

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, 2006, which has been derived from audited financial statements, and the unaudited condensed consolidated financial statements of Continental as of and for the interim periods ended September 30, 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, 2006 included in the Company s S-1/A filed May 10, 2007. Dividends payable of $218,000 at December 31, 2006 have been reclassified to accrued liabilities and other in the accompanying balance sheets to conform to the current year presentation.

Restatement

Subsequent to March 7, 2006, the date on which the Company first filed the registration statement with the Securities and Exchange Commission, management determined for financial reporting purposes, the amount of stock-based compensation expense related to restricted stock and stock options issued to employees should be adjusted to reflect the fair value of restricted stock and stock options in accordance with SFAS No.123(R). In calculating stock-based compensation expense for the nine months ended September 30, 2006, the Company adjusted the fair value of restricted stock and stock options from the historical value based on the price provided for in the plan documents to a probability weighted value that considered the probability of an initial public offering. As a result, the consolidated financial statements of the Company for the nine months ended September 30, 2006, have been restated from the amounts previously reported to reflect the change in stock-based compensation expense. The change resulted in net income being reduced by $4.8 million for the nine months ended September 30, 2006. A summary of the significant effects of the restatement follows:

	For the nine months ended September 30, 2006	
	As Previously Reported	**As Restated**
	(in thousands, except per share data)	

Consolidated statements of operations:				
General and administrative expense	$	19,814	$	24,571
Total operating costs and expenses		153,477		158,234
Income from operations		216,262		211,505
Net income		209,102		204,345
Basic net income per share		1.32		1.29
Diluted net income per share		1.31		1.28
Pro forma				
Net income before income taxes	$	208,970	$	204,213
Pro forma provision for income taxes		79,409		77,601
Pro forma net income	$	129,561	$	126,612
Pro forma basic net income per share	$	0.82	$	0.80
Pro forma diluted net income per share	$	0.81	$	0.79

Table of Contents

Shareholders Equity

On May 14, 2007, the Company announced the pricing of its initial public offering of 29,500,000 shares of its common stock at $15.00 per share. The shares are listed on the New York Stock Exchange under the symbol CLR. The Company sold 8,850,000 shares of common stock in the offering and Harold G. Hamm, the Chairman and Chief Executive Officer and principal shareholder of the Company, sold 20,650,000 shares of common stock in the offering. The offering closed on May 18, 2007. The offering generated gross proceeds of $132.8 million to the Company. The Company incurred underwriters discounts of approximately $8.0 million and other expenses of approximately $2.3 million. The Company netted $290,000, representing 30% of the costs incurred after the Company decided to participate in the offering, against the proceeds of the offering. The balance of the offering costs were expensed as incurred. After the payment of offering expenses the net proceeds were used to repay a portion of the outstanding indebtedness under the credit facility.

On May 14, 2007, 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 has 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.

On May 14, 2007 the Company converted from a subchapter S corporation to a subchapter C corporation. As a result, the Company recorded an adjustment in the amount of $234.1 million to reduce retained earnings to $65.1 million as of the conversion date, which represents the retained earnings balance of the Company when it originally converted from a subchapter C corporation to a subchapter S corporation in May 1997. The amount of the adjustment represents undistributed earnings of $432.5 million, net of the related provision for deferred income taxes of $198.4 million (which was included in the determination of net loss for the nine months ended September 30, 2007).

The Company accounts for stock option grants and restricted stock grants in accordance with SFAS 123(R). The terms of the restricted stock grants and stock option grants stipulate that, until the Company became a reporting company under Section 12 of the Exchange Act, it was required to purchase the vested restricted stock and stock acquired from stock option exercises at each employee s request based upon the purchase price as determined by a formula specified in each award agreement. Additionally, the Company had the right to purchase vested restricted stock and stock acquired from stock option exercises at the same price upon termination of employment for any reason and for a period of two years subsequent to termination of employment. Therefore, the awards were accounted for as liability awards in accordance with SFAS 123(R). The right to sell and requirement to purchase lapsed when the Company became a reporting company under Section 12 of the Exchange Act. Therefore, the liability for equity compensation of approximately $29.8 million was reclassified to additional paid-in capital upon becoming a public reporting company on May 14, 2007. On a prospective basis, the Company will recognize compensation expense for existing stock option and restricted stock grants based on their fair value at May 14, 2007 over the remaining requisite service period. New stock options and restricted stock grants will be valued at fair value at their date of grant and compensation expense recognized over the requisite service period.

Income Taxes

Prior to completion of the public offering on May 14, 2007, 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 became a taxable entity. As a result of the conversion from a subchapter S corporation to a subchapter C corporation on May 14, 2007, the Company recorded a provision of $198.4 million to recognize deferred income taxes related to temporary differences that existed at that date. As a result of the termination of the Company s subchapter S corporation status, the Company will be subject to federal and certain state income taxes at the corporate level at statutory rates.

Table of Contents

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized. Temporary differences arise primarily due to the deductibility for tax purposes of intangible drilling costs and differences in depreciation and depletion rates.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes.* The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 did not have a material impact on the Company s consolidated financial position or results of operations.

Pro forma information (unaudited)

Pro forma adjustments are reflected on the consolidated statements of operations to provide for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*, as if the Company 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 all periods. 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

Recent Accounting Pronouncements

In September 2006, the FASB finalized SFAS No. 157, *Fair Value Measurements* which will become effective in 2008. This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in the Company s consolidated financial statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on the Company s consolidated financial position or results of operations.

In February 2007, the FASB issued SFAS No, 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* This statement provides entities with an option to choose to measure eligible items at fair value at specified election dates. If elected, an entity must report unrealized gains and losses on the item in earnings at each subsequent reporting date. The fair value option may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; is irrevocable (unless a new election date occurs); and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Management does not believe that the implementation of SFAS No. 159 will have a material impact on the Company s consolidated financial statements.

Note 3. Long-term Debt

Long-term debt as of September 30, 2007 and December 31, 2006, consisted of the following:

	September 30, 2007	December 31, 2006
	(in thousands)	
Credit Facility due April 12, 2011	$ 156,500	$ 140,000

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 banks reference rate. The credit facility has a maximum facility amount of $750 million, a borrowing base of $600 million (effective April 17, 2007), subject to semi-annual re-determination, and a commitment level of $300 million. Under the terms of the credit facility, the Company is allowed to set the commitment level up to the borrowing base.

The Company had $143.5 million of unused commitments under the Credit Agreement at September 30, 2007 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. The Company was in compliance with these covenants at September 30, 2007.

Table of Contents

Note 4. 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 the awards were vested and the 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 nine months ended September 30, 2007, because the effect was anti-dilutive.

The following table sets forth the computation of shares used in the basic and diluted earnings per share computations for the three and nine months ended September 30, 2007 and 2006.

	Three months ended September 30, 2007	Three months ended September 30, 2006	Nine months ended September 30, 2007	Nine months ended September 30, 2006
Shares used in basic earnings per share	167,232,271	158,105,651	162,869,042	158,058,109
Effect of dilutive securities:				
Restricted stock	589,242	516,362		548,977
Employee stock options	1,221,246	1,296,823		1,073,347
Shares used in diluted earnings per share	169,042,759	159,918,836	162,869,042	159,680,433

For pro forma purposes, dilutive non-vested restricted shares and stock options of 509,698 shares and 1,167,534 shares, respectively, were considered in the calculation of the diluted weighted average shares outstanding used in computing pro forma diluted net income per share for the nine months ended September 30, 2007.

Note 5. Income Taxes

The following is an analysis of the Company s consolidated income tax provision in conjunction with and subsequent to the conversion 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. Therefore, no provision for income taxes was recorded in 2006.

	Three months ended September 30, 2007 (in thousands)	Nine months ended September 30, 2007 (in thousands)
Current:		
Federal	$	$
State		
Total current benefit		
Deferred:		
Federal	32,356	217,443
State	(2,816)	25,886
Total deferred provision	29,540	243,329
Income tax provision	$ 29,540	$ 243,329

11

Table of Contents

The following table reconciles the income tax provision with income tax at the Federal statutory rate for the three and nine months ended September 30, 2007.

	Three months ended September 30, 2007	Nine months ended September 30, 2007
	(in thousands)	
Federal tax at statutory rate	$ 30,069	$ 73,856
State income taxes, net of federal benefit	2,234	5,486
Eliminate taxes on earnings prior to subchapter C corporation conversion (1)		(32,380)
Non-deductible stock-based compensation	564	878
Other, net	(308)	104
Earnings transferred to subchapter S corporation through election of pro-rata allocation method(2)	(3,019)	(3,019)
Deferred taxes recorded upon conversion to a subchapter C corporation		198,404
Income tax provision	$ 29,540	$ 243,329

(1) 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 and deferred taxes were provided for temporary differences that existed on that date. 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.

(2) During the third quarter of 2007, the Company changed its estimate of income allocation to the subchapter S corporation period assuming the use of the pro-rata income allocation method for tax purposes instead of the specific identification method used for tax and financial reporting purposes at June 30, 2007. Assuming income is allocated using the pro-rata income allocation method, the Company s income for the year is allocated to the subchapter S corporation and the subchapter C corporation based on number of days without regard to when the income was actually earned. The net effect of this change in estimate was a benefit of $3.0 million. There will be some continuing effect of this election in the fourth quarter of 2007, but not in future years.

Significant components of the Company s deferred tax assets and liabilities as of September 30, 2007 are as follows:

	September 30, 2007 (in thousands)
Current:	
Deferred tax assets	
Net operating loss carry forward	$ 5,205
Derivatives	4,716
Accrued expenses	464
Other expenses	73
Total current deferred tax assets	10,458
Non-current:	
Deferred tax assets	
Deferred compensation	6,512
Accrued expenses	372
Other	82
Total non-current deferred tax assets	6,966
Deferred tax liabilities	

Property and equipment		260,753
Total non-current deferred tax liabilities		253,787
Net deferred tax liabilities	$	243,329

Note 6. Cash Flow Information

Net cash provided by operating activities reflects cash interest payments of $8.7 million for the nine months ended September 30, 2007 and $7.2 million for the nine months ended September 30, 2006. Non-cash investing and financing

Table of Contents

activities include asset retirement obligations of $1.7 million and $2.5 million for the nine months ended September 30, 2007 and 2006, respectively. The Company paid cash income taxes of $6.9 million during the nine months ended September 30, 2007 and $1.0 million during the nine months ended September 30, 2006.

Note 7. Commitments and Contingencies

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 September 30, 2007 and December 31, 2006, the Company has provided a reserve of $987,500 and $670,000, 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.

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. The maximum number of shares covered consisted of 11,220,000 shares of the Company s common stock, par value $0.01 per share. On November 10, 2005, the 2000 Plan was terminated. As of September 30, 2007, options covering 1,043,823 shares had been exercised and 73,337 had been cancelled.

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 January 1, 2007	1,576,003	$ 2.06	1,370,666	$ 1.59
Exercised	(306,163)	2.24		
Outstanding September 30, 2007	1,269,840	$ 2.02	1,178,166	$ 1.73

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 nine months ended September 30, 2007 was approximately $2.7 million. At September 30, 2007, the exercisable options had a weighted average life of 4.1 years. There was $0.2 million of unrecognized compensation expense related to non-vested options. The cost is expected to be recognized over a weighted average period of 0.6 years.

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 September 30, 2007, the Company had 4,474,034 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, 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 September 30, 2007, and changes during the nine months ended September 30, 2007, is presented below:

	Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested restricted shares at January 1, 2007	781,407	$ 12.92
Granted	77,484	10.58
Vested	(27,104)	13.47
Forfeited	(41,635)	12.53
Unvested restricted shares at September 30, 2007	790,152	12.70

Table of Contents

The fair value of the restricted shares that vested during the nine months ended September 30, 2007 at their vesting dates was $0.4 million. As of September 30, 2007, there was $3.7 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.3 years.

Historically, the restricted stock and stock option awards required the Company to purchase vested restricted shares and shares acquired by option exercise at the holder s request. As such, the awards were accounted for as liability awards and included in accrued liabilities and other on the accompanying consolidated balance sheet as of December 31, 2006, in the amount of $22.5 million. The requirement to purchase lapsed in connection with the Company s initial public offering. Therefore, the liability for equity compensation of approximately $29.8 million was reclassified to additional paid-in capital during the nine months ended September 30, 2007.

Note 9. 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 will receive a fixed-price of $72.90 per barrel and will pay to the counterparties the average of the prompt NYMEX crude oil futures 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. 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 marks its derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognizes the realized and unrealized change in fair value on derivative instruments in the statements of operations. As of September 30, 2007 the Company had recorded a liability for unrealized losses on derivatives of $12.5 million. For the quarter ended September 30, 2007, the statement of operations contains realized losses of $1.9 million and unrealized losses of $12.5 million on derivatives.

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 registration statement on Form S-1/A filed with the Securities and Exchange Commission on May 10, 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 have been successful in targeting 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. As a result of these efforts, we have grown substantially through the drill bit.

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. See **Liquidity and Capital Resources** *Contractual Commitments* for a discussion of derivative activity.

In the first nine months of 2007, our oil and gas production increased to 7,827 MBoe (28,671 Boe per day), up 19% from the first nine months of 2006. The increase in 2007 production primarily resulted from an increase in production from our Red River units and Bakken field. Oil and natural gas revenues for the first nine months of 2007 increased by 18% to $422.7 million due to increases in volumes. Our realized price per Boe increased $0.18 to $54.68 for the first nine months of

14

Table of Contents

2007 compared to the first nine months of 2006. While we experienced increases in production expense and production tax of a combined total of $17.7 million, or 28%, our increase in combined per unit cost was only 9%, or $0.86 per Boe, due to the increase in sales volumes of 1,162 MBoe, or 18%. Oil sales volumes were 96 MBbls less than oil production for the first nine months of 2007 and 10 MBbls less for the same period in 2006, due to an increase in crude oil inventory for pipeline line fill and temporarily stored barrels. Our cash flow from operating activities for the nine months ended September 30, 2007, was $278.4 million, a decrease of $10.6 million from $289.0 million provided by our operating activities during the comparable 2006 period. The decrease in operating cash flows was mainly due to changes in working capital items including an increase in accounts receivables, both revenue and joint interest, an increase in crude oil inventory, and reduction of trade accounts payable. During the nine months ended September 30, 2007, we invested $402.1 million (inclusive of non-cash accruals of $32.2 million) in our capital program primarily in the Red River units, the Bakken field and the Woodford Shale play.

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 three and nine months ended September 30, 2007 compared to the corresponding periods in the prior year.

	Three months ended September 30,		Nine months ended September 30,	
	2007	**2006**	**2007**	**2006**
Average daily production:				
Crude oil (Bopd)	24,224	21,352	23,672	19,977
Natural gas (Mcfd)	31,499	25,668	29,994	24,744
Crude oil equivalent (Boepd) (1)	29,474	25,630	28,671	24,101
Average prices: (2)				
Crude oil ($/Bbl)	$ 69.44	$ 61.67	$ 58.92	$ 58.05
Natural gas ($/Mcf)	$ 5.29	$ 5.77	$ 5.82	$ 6.22
Crude oil equivalent ($/Boe)	$ 62.61	$ 57.24	$ 54.68	$ 54.50
Production expense ($/Boe) (2)	$ 7.72	$ 6.61	$ 7.53	$ 7.03
General and administrative expense ($/Boe) (2)	$ 2.34	$ 1.01	$ 3.58	$ 3.74
EBITDAX (in thousands) (3)	$ 132,817	$ 112,503	$ 332,472	$ 287,009
Net income (loss) (in thousands) (4)	$ 56,372	$ 87,991	$ (32,312)	$ 204,345
Diluted net income (loss) per share	$ 0.33	$ 0.55	$ (0.20)	$ 1.28

(1) During the month of September 2007, our average daily production was 30,476 Boepd reflecting additional gas production in the Red River units as a result of the new Hiland Badlands plant and increases in other production.

(2) Oil sales volumes were 49 MBbls less than oil production for the three months ended September 30, 2007 and 41 MBbls more than oil production for the three months ended September 30, 2006. For the nine months ended September 30, 2007 oil sales volumes were 96 MBbls less than oil production and 10 MBbls less than oil production for the nine months ended September 30, 2006. Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

(3) 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.**

(4) Prior to the public offering, we were a subchapter S corporation and income taxes were payable by our shareholders and as a result, there was no provision for income taxes for the periods ended September 30, 2006. 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.

Table of Contents

Results of Operations

The three months ended September 30, 2007 compared to the three months ended September 30, 2006

(in thousands, except price data)	3rd Quarter 2007	3rd Quarter 2006
Oil and natural gas sales	$ 166,704	$ 137,281
Revenues	156,772	140,873
Operating expenses	68,404	50,430
Income from operations	88,368	90,443
Net income before income taxes	85,912	87,859
Provision (benefit) for income taxes	29,540	(132)
Net income (loss)	$ 56,372	$ 87,991
Production Volumes:		
Oil and condensate (MBbl)	2,229	1,964
Natural gas (MMcf)	2,898	2,362
Oil equivalents (MBoe)	2,712	2,358
Sales Volumes:		
Oil and condensate (MBbl)	2,180	2,005
Natural gas (MMcf)	2,898	2,362
Oil equivalents (MBoe)	2,663	2,399
Average Prices [1]:		
Oil and condensate ($/Bbl)	$ 69.44	$ 61.67
Natural gas ($/Mcf)	$ 5.29	$ 5.77
Oil equivalents ($/Boe)	$ 62.61	$ 57.24

(1) Excluding any effect of derivative transactions.

Production

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

	3rd Quarter 2007		2006			
	Volume	Percent	Volume	Percent	Volume Increase	Percent Increase
Oil and condensate (MBbl) [1]	2,229	82%	1,964	83%	265	13%
Natural gas (MMcf)	2,898	18%	2,362	17%	536	23%
Total oil equivalents (MBoe)	2,712	100%	2,358	100%	354	15%

	3rd Quarter 2007		2006			
	MBoe	Percent	MBoe	Percent	Volume Increase (Decrease)	Percent Increase (Decrease)
Rocky Mountain [1]	2,219	82%	1,894	80%	325	17%
Mid-Continent	451	17%	390	17%	61	16%
Gulf Coast	42	1%	74	3%	(32)	(43)%
Total oil equivalents (MBoe)	2,712	100%	2,358	100%	354	15%

(1) Oil sales volumes were 49 MBbls less than oil production volumes for the three months ended September 30, 2007 and 41 MBbls more than oil production volumes for the three months ended September 30, 2006.

Oil production volumes increased 13% during the three months ended September 30, 2007 in comparison to the three months ended September 30, 2006. Production increases in the Red River units contributed incremental volumes in excess of 2006 levels of 221 MBbls and the Bakken Field units contributed 73 MBbls, of incremental production. Initial production commenced in the Bakken field in August 2003 and has increased thereafter, as we have continued exploration and development activities within the Montana and North Dakota portions of the field. Favorable results from the enhanced recovery program and increased density drilling have been the primary contributors to production growth in the Red River units. Gas volumes increased 536 MMcf, or 23%, during the three months ended September 30, 2007 compared to the same time period in 2006. Production from the Mid-Continent region increased 441 MMcf reflecting the successful drilling in the Woodford Shale play and other Mid-Continent areas. The Rocky Mountain region increased 261 MMcf mainly in the Bakken and other Rockies area. Delays in completion of the new Hiland Partners Badlands Plant limited natural gas sales in the Red River units. Through September 30, 2007, we sold 197 MMcf of gas from the Red River units through the new plant after it became operational in late August 2007. We have invested a minimal amount of capital in our Gulf Coast region resulting in a 166 MMcf decline in gas production in this area.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the three months ended September 30, 2007 were $166.7 million, a 21% increase from sales of $137.3 million for the comparable period in 2006. Our sales volumes increased 264 MBoe or 11% over the 2006 volumes due to the continuing success of our secondary recovery and drilling programs. Our realized price per Boe increased $5.37 to $62.61 for the three months ended September 30, 2007 from $57.24 for the three months ended September 30, 2006. During 2007, 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 September 30, 2007 was $5.88 as compared to $8.88 for the comparable period in 2006. Factors contributing to the higher differentials in 2006 included Canadian oil imports, increases in production in the Rocky Mountain region, refinery downtime in the Rocky Mountain region, downstream transportation capacity constraints, and reduced seasonal demand for gasoline. Crude oil differentials are better during 2007 due to enhanced transportation capacity and efforts by us to move crude oil to more favorable markets.

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 lower quality crude oil, or 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 September 30, 2007 and $0.7 million for the three months ended September 30, 2006. Prices for reclaimed oil sold from our central treating unit were $6.36 per barrel higher for the three months ended September 30, 2007 compared to the same 2006 period, and the number of barrels sold increased approximately 5,000 which increased reclaimed oil income by $0.5 million contributing to an overall increase in oil and gas service operations revenue of $0.9 million for the three months ended September 30, 2007. Associated oil and natural gas service operations expenses increased $0.5 million to $2.4 million during the three months ended September 30, 2007 from $1.9 million during the three months ended September 30, 2006 due mainly to the increased barrels treated during the three months ended September 30, 2007 compared to the three months ended September 30, 2006.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $4.7 million, or 30% during the three months ended September 30, 2007 to $20.6 million from $15.9 million during the three months ended September 30, 2006. The increase is a result of new wells being drilled and workovers and repairs on existing wells. During the three months ended September 30, 2007, we participated in the completion of 70 gross (29.1 net) wells. Production expense per Boe increased to $7.72 per Boe for the three months ended September 30, 2007 from $6.61 per Boe for the three months ended September 30, 2006.

Production taxes increased $2.1 million, or 32% during the three months ended September 30, 2007 compared to the three months ended September 30, 2006 as a result of increasing prices and sales volumes. The majority of the production tax increase was in the Rocky Mountain region, which is partially due to an increase of 326 MBoe sold in the three months ended September 30, 2007 compared to the three months ended September 20, 2006. Production tax as a percentage of oil and natural gas sales was 5.2% for the three months ended September 30, 2007 compared to 4.8% for the three months ended September 30, 2006. 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, new horizontal wells qualify for a tax incentive and are taxed at 0.76% during the first 18 months of production. After the 18 month incentive period expires, the tax rate increases to 9.26%. During the twelve month period from September 30, 2006 to September 30, 2007, 34 wells had reached the end of the 18 month incentive period and the tax rate increased from 0.76% to 9.26%. As of September 30, 2007 we are receiving the incentive tax rate on 54 wells. Our overall rate is expected to increase as production tax incentives we currently receive for horizontal wells in Montana continue to reach the end of the 18 month incentive period. We are also receiving a 6% tax incentive on horizontal wells drilled in the Woodford shale play in Oklahoma. The incentive period continues on a well for four years or until the revenue exceeds the cost to drill and complete the well, In North Dakota, we are receiving a 4.5% tax credit on horizontal Bakken wells spud after July 1, 2007 and completed before June 30, 2008. The incentive expires on the earliest to occur of 75,000 barrels of production or eighteen months.

17

Table of Contents

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

On a Boe Basis	3rd Quarter 2007	2006	Percent Increase
Production expense ($/Boe)	$ 7.72	$ 6.61	17%
Production tax ($/Boe)	3.27	2.76	18%
Production expense and tax ($/Boe)	$ 10.99	$ 9.37	17%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses decreased $1.2 million during the three months ended September 30, 2007 to $2.8 million. The decrease is due primarily to a decrease in dry hole expense of $1.6 million during the three months ended September 30, 2007 to $1.1 million. Seismic expense increased $0.2 million. Exploration capital expenditures were $64.2 million for the three months ended September 30, 2007 compared to $24.9 million for the three months ended September 30, 2006. The Rocky Mountain region made up 51%, or $33.1 million of the 2007 exploration capital expenditures and the Mid-Continent region made up the remaining balance of $31.1 million.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A on oil and gas properties increased $5.0 million in 2007 due to increased production and additional properties being added through our drilling program. The DD&A rate on oil and gas properties for the three months ended September 30, 2007 was $8.48 per Boe compared to $7.34 per Boe for the three months ended September 30, 2006 reflecting additional costs incurred to develop proved undeveloped reserves and higher costs for drilling and completing wells. Accretion expense increased approximately $91,000 for the three months ended September 30, 2007 compared to the three months ended September 30, 2006. We expect our DD&A rate to continue to increase as we drill for higher cost reserves.

Property Impairments. Property impairments increased during the three months ended September 30, 2007 by $2.8 million to $4.1 million compared to $1.3 million during the three months ended September 30, 2006. Impairment provisions for developed oil and gas properties were approximately $1.1 million for the three months ended September 30, 2007 compared to $21,000 for the three months ended September 30, 2006. Impairment of non-producing properties increased $1.7 million during the three months ended September 30, 2007 to $3.0 million, due to lease expirations in the Bakken field. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other 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 $3.8 million to $6.2 million during the three months ended September 30, 2007 compared to the same period in 2006. General and administrative expense includes non-cash charges for stock-based compensation which increased $3.4 million for the three months ended September 30, 2007 compared to the same period in 2006. For the quarter ended September 30, 2006, the non-cash stock-based compensation expense was ($2.2) million reflecting a decrease in the fair value of the associated restricted stock and stock options that were classified as liability awards prior to our initial public offering. General and administrative expenses excluding equity compensation increased $0.4 million for the three months ended September 30, 2007 compared to the three months ended September 30, 2006. On a volumetric basis, general and administrative expense was $2.34 per Boe for the three months ended September 30, 2007 compared to $1.01 per Boe for the three months ended September 30, 2006.

Interest Expense. Interest expense decreased 11%, or $0.3 million for the three months ended September 30, 2007 compared to the three months ended September 30, 2006, due to a lower average outstanding debt balance on our credit facility of $154.1 million for the three months ended September 30, 2007 compared to $172.9 million for the three months ended September 30, 2006. The weighted average interest rate on our credit facility was slightly higher at 6.52% for the three months ended September 30, 2007 compared to 6.46% for the three months ended September 30, 2006. During the month of May 2007, we reduced our outstanding debt on our credit facility by $141.0 million, utilizing proceeds received from our public offering. At September 30, 2007, our outstanding balance was $156.5 million.

Income Taxes. Income taxes for the three months ended September 30, 2007 were $29.5 million for an effective tax rate of 34.4%. During the third quarter of 2007, the Company changed its estimate of income allocation to the subchapter S corporation period assuming the use of the pro-rata income allocation method for tax purposes instead of the specific identification method used for tax and financial reporting purposes at June 30, 2007. Assuming income is allocated using the pro-rata income allocation method, the Company s income for the year is allocated to the subchapter S corporation and the subchapter C corporation based on number of days without regard to when the income was actually earned. The net effect of

Table of Contents

this change in estimate was a benefit of $3.0 million. There will be some continuing effect of this election in the fourth quarter of 2007, but not in future years. See Footnote 5 of Notes to Unaudited Condensed Consolidated Financial Statements for more information.

Nine months ended September 30, 2007 compared to the nine months ended September 30, 2006

	September 30,	
(in thousands, except price data)	**2007**	**2006**
Oil and natural gas sales	$ 422,734	$ 358,004
Revenues	423,221	369,739
Operating expenses	203,557	158,234
Income from operations	219,664	211,505
Net income before income taxes	211,017	204,213
Provision (benefit) for income taxes	243,329	(132)
Net income (loss)	$ (32,312)	$ 204,345
Production Volumes:		
Oil and condensate (MBbl)	6,462	5,454
Natural gas (MMcf)	8,188	6,755
Oil equivalents (MBoe)	7,827	6,580
Sales Volumes:		
Oil and condensate (MBbl)	6,366	5,444
Natural gas (MMcf)	8,188	6,755
Oil equivalents (MBoe)	7,731	6,570
Average Prices [1]:		
Oil and condensate ($/Bbl)	$ 58.92	$ 58.05
Natural gas ($/Mcf)	$ 5.82	$ 6.22
Oil equivalents ($/Boe)	$ 54.68	$ 54.50

(1) Excluding any effect of derivative transactions.

Production

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

	Nine Months ended September 30,					
	2007		**2006**		**Volume**	**Percent**
	Volume	**Percent**	**Volume**	**Percent**	**increase**	**increase**
Oil and condensate (MBbl) [1]	6,462	83%	5,454	83%	1,008	18%
Natural gas (MMcf)	8,188	17%	6,755	17%	1,433	21%
Total oil equivalents (MBoe)	7,827	100%	6,580	100%	1,247	19%

	Nine Months ended September 30,				Volume	Percent
	2007		**2006**		**increase**	**increase**
	MBoe	**Percent**	**MBoe**	**Percent**	**(decrease)**	**(decrease)**
Rocky Mountain [1]	6,356	81%	5,195	79%	1,161	22%
Mid-Continent	1,324	17%	1,103	17%	221	20%
Gulf Coast	147	2%	282	4%	(135)	(48)%
Total oil equivalents (MBoe)	7,827	100%	6,580	100%	1,247	19%

(1) Oil sales volumes were 96 MBbls less than oil production volumes for the nine months ended September 30, 2007 and 10 MBbls less than oil production volumes for the nine months ended September 30, 2006.

Oil production volumes increased 18% during the nine months ended September 30, 2007 in comparison to the nine months ended September 30, 2006. Production increases in the Red River units contributed incremental volumes in excess of 2006 levels of 677 MBbls, and the Bakken field contributed 376 MBbls of incremental production. Initial production commenced in the Bakken field in August 2003 and has increased thereafter, as we have continued exploration and development activities within the Montana and North Dakota portions of the field. Favorable results from the enhanced recovery program and increased density drilling have been the primary contributors to production growth in the Red River units. Gas volumes increased 1,433 MMcf, or 21%, during the nine months ended September 30, 2007 compared to the same time period in 2006. The majority of the increase, 1,320 MMcf was from the Mid-Continent region. The Rocky Mountain gas production was up 690 MMcf for the nine months ended September 30, 2007 compared to the same period in 2006. The increase was mainly in the Bakken field and the other Rockies area. Delays in completion of the new Hiland Partners Badlands Plant limited natural gas sales in the Red River units. Through September 30, 2007, we sold 197MMcf of gas from the Red River units through the new plant after it became operational in late August 2007. We have invested a minimal amount of capital in our Gulf Coast region resulting in a decline in production in this area of 577 MMcf for the nine months ended September 30, 2007 compared to the same time period in 2006.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the nine months ended September 30, 2007 were $422.7 million, an 18% increase from sales of $358.0 million for the comparable period in 2006. Our sales volumes increased 1,161 MBoe or 18% over the 2006 volumes due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe increased $0.18 to $54.68 for the nine months ended September 30, 2007 from $54.50 for the nine months ended September 30, 2006. During 2007, the differential between NYMEX calendar month average crude oil prices and our realized crude oil prices narrowed. The differential per barrel for the nine months ended September 30, 2007 was $7.46 compared to $13.28 for the comparable period in 2006. Factors contributing to the higher differentials in 2006 included Canadian oil imports, increases in production in the Rocky Mountain region, refinery downtime in the Rocky Mountain region, downstream transportation capacity constraints, and reduced seasonal demand for gasoline. Crude oil differentials are better during 2007 due to additional transportation capacity and efforts by us to move crude oil to more favorable markets.

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 lower quality crude oil, or reclaimed oil. We sold high-pressure air from our Red River units to a third party and recorded revenues of $2.4 million for the nine months ended September 30, 2007 and $2.2 million for the nine months ended September 30, 2006. Prices for reclaimed oil sold from our central treating unit were lower for the nine months ended September 30, 2007 than the comparable 2006 period, however, the number of barrels sold increased approximately 53,000 barrels which increased reclaimed oil income by $3.0 million contributing to an overall increase in oil and gas service operations revenue of $3.1 million for the nine months ended September 30, 2007. Associated oil and natural gas service operations expenses increased $2.2 million to $8.8 million during the nine months ended September 30, 2007 from $6.6 million during the nine months ended September 30, 2006 due mainly to increased barrels treated in 2007.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $12.0 million, or 26% during the nine months ended September 30, 2007 to $58.2 million from $46.2 million during the nine months ended September 30, 2006. The increase is a result of new wells drilled, repairs, and increased energy costs. During the first nine months of 2007, we participated in the completion of 177 gross (84.6 net) wells. Production expense per Boe increased to $7.53 per Boe for the nine months ended September 30, 2007 from $7.03 per Boe for the nine months ended September 30, 2006.

Production taxes increased $5.7 million, or 34% during the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006 primarily as a result of increased sales volumes. The majority of the production tax increase was in the Rocky Mountain region due to an increase of 1,161 MBoe sold in the nine months ended September 30, 2007compared to the nine months ended September 30, 2006. Production tax as a percentage of oil and natural gas sales was 5.3% for the nine months ended September 30, 2007 compared to 4.6% for the nine months ended September 30, 2006. 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, new horizontal wells qualify for a tax incentive and are taxed at 0.76% during the first 18 months of production. After the 18 month incentive period expires, the tax rate increases to 9.26%. During the twelve month period from September 30, 2006 to September 30, 2007, 34 wells had reached the end of the 18 month incentive period and the tax rate increased from 0.76% to 9.26%. Our overall rate is expected to increase as production tax incentives received for horizontal wells in Montana reach the end of the 18 month incentive period. We are also receiving a 6% tax incentive on horizontal wells drilled in the Woodford shale play in Oklahoma. The incentive period continues on a well for four years or until the revenue exceeds the cost to drill and complete the well. In North Dakota, we are receiving a 4.5% tax credit on horizontal Bakken wells spud after July 1, 2007 and completed before June 30, 2008. The incentive expires on the earliest to occur of 75,000 barrels of production or eighteen months.

Table of Contents

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

On a Boe Basis	Nine Months ended September 30, 2007	2006	Percent Increase
Production expense ($/Boe)	$ 7.53	$ 7.03	7%
Production tax ($/Boe)	2.89	2.53	14%
Production expense and tax ($/Boe)	$ 10.42	$ 9.56	9%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses decreased $2.4 million in the nine months ended September 30, 2007 to $6.7 million due primarily to a decrease in dry hole expense of $2.9 million offset by an increase in seismic expense of $0.3 million and smaller increases in various other expenses. The majority of the dry hole costs were in the Mid-Continent region in the 2006 period and in the Rocky Mountain region in the same period in 2007. Exploration capital expenditures were $120.4 million for the nine months ended September 30, 2007 compared to $46.0 million for the nine months ended September 30, 2006. The Mid-Continent region made up 51%, or $61.9 million of 2007 exploration capital expenditures, and the Rocky Mountain region made up the remaining balance.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A on oil and gas properties increased $20.5 million in 2007 due to increased production and additional properties being added through our drilling program. The DD&A rate on oil and gas properties for the nine months ended September 30, 2007 was $8.33 per Boe compared to $6.69 per Boe for the nine months ended September 30, 2006 reflecting additional costs incurred to develop proved undeveloped reserves and higher costs for drilling and completing wells. Accretion expense increased approximately $0.2 million for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006.

Property Impairments. Property impairments increased in the nine months ended September 30, 2007 by $3.9 million to $13.0 million compared to $9.1 million during the nine months ended September 30, 2006 reflecting higher lease expirations in the Bakken field and amortization of new fields. Impairment of non-producing properties increased $5.4 million during the nine months ended September 30, 2007 to $9.1 million compared to $3.7 million for the same period in 2006. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period. Impairment provisions for developed oil and gas properties were approximately $3.9 million for the nine months ended September 30, 2007 compared to approximately $5.3 million for the nine months ended September 30, 2006.

General and Administrative Expense. General and administrative expense increased $3.1 million to $27.7 million during the nine months ended September 30, 2007 from $24.6 million during the comparable period of 2006. General and administrative expense includes non-cash charges for stock-based compensation of $12.1 million and $9.7 million for the nine months ended September 30, 2007 and 2006, respectively. On a volumetric basis, general and administrative expense was $3.58 per Boe for the nine months ended September 30, 2007 compared to $3.74 per Boe for the nine months ended September 30, 2006.

Gain on Sale of Assets. Gains on miscellaneous asset sales for the nine months ended September 30, 2007 and 2006 totaled approximately $0.3 million, respectively.

Interest Expense. Interest expense increased 16%, or $1.3 million for the nine months ended September 30, 2007 compared to the nine months ended September 30, 2006, due to higher average interest rates and outstanding debt balance on our credit facility of $183.6 million for the nine months ended September 30, 2007 compared to $163.8 million for the nine months ended September 30, 2006. The weighted average interest rate on our credit facility was 6.53% for the nine months ended September 30, 2007 and 5.86% for the same period in 2006. During the month of May 2007, we reduced our outstanding debt on the credit facility by $141.0 million, utilizing proceeds received from our public offering. At September 30, 2007, our outstanding long-term debt balance was $156.5 million.

Table of Contents

Income Taxes. Income taxes for the nine months ended September 30, 2007 were $243.3 million and included $198.4 million recorded to recognize deferred taxes upon the conversion from a subchapter S corporation to a subchapter C corporation on May 14, 2007 for timing differences that existed at that date. See Footnote 5 of Notes to Unaudited Condensed Consolidated Financial Statements for more information.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facility. On May 14, 2007, we completed an initial public offering in which we generated net proceeds of $122.5 million. 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 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. On January 10, 2007 and March 6, 2007, we declared cash dividends of approximately $18.8 million and $33.3 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. On May 14, 2007, we completed our initial public offering and in conjunction therewith, converted from a subchapter S corporation to a subchapter C corporation and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. At September 30, 2007 and December 31, 2006, we had cash and cash equivalents of $5.5 million and $7.0 million, respectively and available borrowing capacity on our credit facility of $143.5 million and $160.0 million, respectively. On April 17, 2007, the credit facility was amended to increase the borrowing base to $600.0 million. On May 18, 2007, we paid down the debt outstanding under our credit facility by $122.9 million primarily utilizing proceeds from our initial public offering. The amount borrowed under the credit facility at October 31, 2007 was $177.5 million. We have elected to have a commitment level of $300.0 million to reduce our commitment fees and, therefore, as of October 31, 2007, have an available borrowing capacity of $122.5 million.

Cash Flow From Operating Activities

Our net cash provided by our operating activities for the nine months ended September 30, 2007, was $278.4 million, a decrease of $10.6 million from $289.0 million provided by our operating activities during the comparable 2006 period. The decrease in operating cash flows was mainly due to changes in working capital items including an increase in accounts receivables, crude oil inventory, and a reduction of trade accounts payable.

Cash Flow From Investing Activities

During the nine months ended September 30, 2007 and 2006 we had cash flows used in investing activities (excluding asset sales) of $370.0 million and $221.3 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 Oklahoma Woodford Shale play.

Cash Flow From Financing Activities

Net cash provided by financing activities of $87.9 million for the nine months ended September 30, 2007 was mainly the result of the proceeds of our initial public offering net of amounts used for capital expenditures and to pay cash dividends. Net cash used in financing activities was $71.2 million for the nine months ended September 30, 2006 and was attributable to cash dividends paid.

Capital Expenditures

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. In August 2007 the Board of Directors approved an increase of $45.0 million in our 2007 capital expenditure budget from $437.0 million to $482.0 million. During the first nine months of 2007, we participated in the completion of 177 gross (84.6 net) wells and invested a total of $402.1 million including $371.7 million in drilling and capital facilities and $26.7 million for undeveloped acreage. 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.

Although we cannot 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 2007 capital budget.

Table of Contents

Recent Accounting Pronouncements

In September 2006, the FASB finalized SFAS No. 157, *Fair Value Measurements* which will become effective in 2008. This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in our consolidated financial statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on our consolidated financial position or results of operations.

In February 2007, the FASB issued SFAS No, 159, *The Fair Value Option for Financial Assets and Financial Liabilities.* This statement provides entities with an option to choose to measure eligible items at fair value at specified election dates. If elected, an entity must report unrealized gains and losses on the item in earnings at each subsequent reporting date. The fair value option may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; is irrevocable (unless a new election date occurs); and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Management does not believe that the implementation of SFAS No. 159 will have a material impact on our consolidated financial statements.

Contractual Commitments

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 will receive a fixed-price of $72.90 per barrel and will pay to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month.

Critical Accounting Policies

There has been no change in our critical accounting policies from those disclosed in our Prospectus dated May 14, 2007 filed with the Securities and Exchange Commission on May 16, 2007 other than as follows.

Derivative accounting 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 will receive a fixed-price of $72.90 per barrel and will pay 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 mark our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognize the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of operations.

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 (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). 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

Table of Contents

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 September 30,		Nine months ended September 30,	
	2007	2006	2007	2006 (as restated)
Net income (loss)	$ 56,372	$ 87,991	$ (32,312)	$ 204,345
Unrealized derivative loss	12,542		12,542	
Income tax provision (benefit)	29,540	(132)	243,329	(132)
Interest expense	2,774	3,101	9,854	8,522
Depreciation, depletion, amortization and accretion	23,568	18,395	67,306	46,376
Property impairments	4,099	1,347	12,992	9,080
Exploration expense	2,758	4,018	6,664	9,085
Equity compensation	1,164	(2,217)	12,097	9,733
EBITDAX	$ 132,817	$ 112,503	$ 332,472	$ 287,009

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

General

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.

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 in the past, through the utilization of derivatives, including zero-cost collars and fixed price contracts. We had no hedging contracts in place during 2006 or through June 30, 2007. 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 will receive a fixed-price of $72.90 per barrel and will pay 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 mark our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognize the realized and unrealized change in fair value as a gain (loss) on derivative instruments in the statements of operations. As of September 30, 2007 we recorded a liability for unrealized losses on derivatives of $12.5 million. During the quarter ended September 30, 2007, we had realized losses on derivatives of $1.9 million. As of September 30, 2007, a one dollar increase or decrease in the NYMEX crude futures price would result in approximately $2.1 million loss or gain over the life of our derivatives. At October 31, 2007 the fair market value of unrealized derivatives losses was $33.3 million.

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

Table of Contents

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 $177.5 million outstanding under our credit facility at October 31, 2007. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.8 million per year. Our long-term debt matures in 2011 and the weighted-average interest rate at September 30, 2007 is 6.42%.

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 September 30, 2007 that have materially affected or is reasonably likely to materially effect our internal controls over financial reporting.

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 have been no material changes to the risk factors previously disclosed in our prospectus dated May 14, 2007 and filed with the Securities and Exchange Commission on May 16, 2007 relating to our initial public offering of common stock (the Prospectus) (except for the additional risk factor shown below). The risk factors listed on pages 11 through 22 under the heading Risk Factors in the Prospectus are incorporated herein by reference.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we on occasion, enter into derivative instruments for a portion of our oil and/or natural gas production, including collars and price-fix swaps. In July 2007, we entered into fixed price swaps covering 10,000 barrels of oil per day for August 2007 through April 2008 at a price of $72.90 per barrel. We have not designated any of our derivative instruments as hedges for accounting purposes and will record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments will be recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments. Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;

the counter-party to the derivative instrument defaults on its contract obligations; or

there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas.

Table of Contents

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 Programs
July 1, 2007 to July 31, 2007				
August 1, 2007 to August 31, 2007	1,647	15.27		
September 1, 2007 to September 30, 2007	48,934	16.20		
Total	50,581	16.17		

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* under 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

Not applicable.

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: November 9, 2007	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