CONTINENTAL RESOURCES INC
Form 10-Q
August 07, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2009

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	**(I.R.S. Employer**
incorporation or organization)	**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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

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

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

169,635,783 shares of our $0.01 par value common stock were outstanding on July 31, 2009.

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When we refer to us, we, ours, Company, or Continental we are describing Continental Resources, Inc. and / or our subsidiary.

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Glossary of Oil and Natural Gas Terms

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

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

Bcf. One billion cubic feet of natural gas.

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

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

DD&A. Depreciation, depletion, amortization and accretion.

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

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

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

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

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

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

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

Mcf. One thousand cubic feet of natural gas.

MBoe. One thousand Boe.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

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

Proved undeveloped reserves or PUD. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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

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PART I. Financial Information

ITEM 1. Financial Statements

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Balance Sheets

	June 30, 2009 (Unaudited)	December 31, 2008
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 5,071	$ 5,229
Receivables:		
Oil and natural gas sales	100,562	63,659
Affiliated parties	6,596	14,914
Joint interest and other, net	69,888	150,506
Inventories	40,158	22,210
Deferred and prepaid taxes	2,982	18,810
Prepaid expenses and other	4,769	2,367
Total current assets	230,026	277,695
Net property and equipment, based on successful efforts method of accounting	1,990,046	1,935,143
Debt issuance costs, net	4,049	3,041
Total assets	$ 2,224,121	$ 2,215,879
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 104,930	$ 260,188
Accounts payable trade to affiliated parties	13,000	25,730
Accrued liabilities and other	28,354	34,769
Revenues and royalties payable	58,165	78,160
Current portion of asset retirement obligation	2,770	4,747
Total current liabilities	207,219	403,594
Long-term debt	592,000	376,400
Other noncurrent liabilities:		
Deferred tax liability	437,745	445,752
Asset retirement obligation, net of current portion	43,503	39,883
Other noncurrent liabilities	2,982	1,542
Total other noncurrent liabilities	484,230	487,177
Commitments and contingencies (Note 7)		
Shareholders equity:		
Preferred stock, $0.01 par value: 25,000,000 shares authorized; no shares issued and outstanding		
Common stock, $0.01 par value; 500,000,000 shares authorized, 169,636,609 shares issued and outstanding at June 30, 2009; 169,558,129 shares issued and outstanding at December 31, 2008	1,696	1,696
Additional paid-in capital	425,123	420,054
Retained earnings	513,853	526,958
Total shareholders equity	940,672	948,708
Total liabilities and shareholders equity	$ 2,224,121	$ 2,215,879

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

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Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Operations

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands, except per share data)		(In thousands, except per share data)	
Revenues:				
Oil and natural gas sales	$ 141,028	$ 278,311	$ 226,845	$ 487,010
Oil and natural gas sales to affiliates	5,411	19,308	12,162	36,034
Gain (loss) on mark-to-market derivative instruments	890	(3,358)	890	(7,966)
Oil and natural gas service operations	4,432	9,173	8,472	16,007
Total revenues	151,761	303,434	248,369	531,085
Operating costs and expenses:				
Production expenses	21,458	22,868	38,732	41,818
Production expense to affiliates	2,580	4,085	7,732	8,208
Production tax and other expenses	11,629	17,695	18,451	30,470
Exploration expense	1,530	5,731	8,649	10,993
Oil and natural gas service operations	2,694	6,468	5,097	10,698
Depreciation, depletion, amortization and accretion	53,148	28,062	103,845	56,708
Property impairments	23,275	3,153	58,700	7,673
General and administrative	9,351	10,276	19,635	17,807
Gain on sale of assets	(85)	(133)	(221)	(212)
Total operating costs and expenses	125,580	98,205	260,620	184,163
Income (loss) from operations	26,181	205,229	(12,251)	346,922
Other income (expense):				
Interest expense	(4,723)	(2,865)	(9,310)	(6,276)
Other	301	248	448	547
	(4,422)	(2,617)	(8,862)	(5,729)
Income (loss) before income taxes	21,759	202,612	(21,113)	341,193
Provision (benefit) for income taxes	8,251	75,305	(8,008)	125,915
Net income (loss)	$ 13,508	$ 127,307	$ (13,105)	$ 215,278
Basic net income (loss) per share	$ 0.08	$ 0.76	$ (0.08)	$ 1.28
Diluted net income (loss) per share	$ 0.08	$ 0.75	$ (0.08)	$ 1.27

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

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Continental Resources, Inc. and Subsidiary

Condensed Consolidated Statements of Shareholders Equity

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Total shareholders equity
		(in thousands, except share data)			
Balance, January 1, 2008	168,864,015	$ 1,689	$ 415,435	$ 206,008	$ 623,132
Net income				320,950	320,950
Stock-based compensation			9,927		9,927
Stock options:					
Exercised	436,327	4	1,438		1,442
Repurchased and canceled	(82,922)	(1)	(4,017)		(4,018)
Restricted stock:					
Issued	461,120	5			5
Repurchased and canceled	(91,568)	(1)	(2,729)		(2,730)
Forfeited	(28,843)				
Balance, December 31, 2008	169,558,129	$ 1,696	$ 420,054	$ 526,958	$ 948,708
Net loss (unaudited)				(13,105)	(13,105)
Stock-based compensation (unaudited)			5,422		5,422
Stock options:					
Exercised (unaudited)	7,000		5		5
Restricted stock:					
Issued (unaudited)	109,496				
Repurchased and canceled (unaudited)	(14,012)		(358)		(358)
Forfeited (unaudited)	(24,004)				
Balance, June 30, 2009 (unaudited)	169,636,609	$ 1,696	$ 425,123	$ 513,853	$ 940,672

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

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Continental Resources, Inc. and Subsidiary

Unaudited Consolidated Statements of Cash Flows

	Six months ended June 30, 2009	2008
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (13,105)	$ 215,278
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	107,948	56,656
Property impairments	58,700	7,673
Change in derivative fair value	(890)	(26,703)
Equity compensation	5,422	3,895
Tax benefit of excess non qualified stock option deduction		(3,255)
Provision (benefit) for deferred income taxes	(8,008)	100,811
Dry hole costs	4,992	1,646
Others, net	831	177
Changes in assets and liabilities:		
Accounts receivable	52,033	(112,675)
Inventories	(17,948)	(7,919)
Prepaid expenses and other	13,523	(336)
Accounts payable	(96,873)	17,918
Revenues and royalties payable	(19,995)	18,217
Accrued liabilities and other	(5,577)	26,538
Other noncurrent liabilities	1,440	49
Net cash provided by operating activities	82,493	297,970
Cash flows from investing activities:		
Exploration and development	(296,099)	(275,504)
Purchase of oil and gas properties	(437)	(71,003)
Purchase of other property and equipment	(628)	(3,529)
Proceeds from sale of assets	1,391	1,307
Net cash used in investing activities	(295,773)	(348,729)
Cash flows from financing activities:		
Revolving credit facility	334,100	184,000
Repayment of revolving credit facility	(118,500)	(129,000)
Debt issuance costs	(2,118)	(45)
Repurchase of equity grants	(358)	(4,177)
Dividends to shareholders	(7)	(6)
Exercise of options	5	1,161
Tax benefit of excess non qualified stock option deduction		3,255
Net cash provided by financing activities	213,122	55,188
Net change in cash and cash equivalents	(158)	4,429
Cash and cash equivalents at beginning of period	5,229	8,761
Cash and cash equivalents at end of period	$ 5,071	$ 13,190

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

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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 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

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by accounting principles generally accepted in the United States (U.S. GAAP), although the Company believes that the disclosures are adequate to make the information not misleading. You should read this Form 10-Q along with the Company s Annual Report on Form 10-K for the year ended December 31, 2008 (2008 Form 10-K), which includes a summary of the Company s significant accounting policies and other disclosures.

The financial statements as of June 30, 2009 and for the three and six month periods ended June 30, 2009 and 2008 are unaudited. The Condensed Consolidated Balance Sheet as of December 31, 2008 was derived from the audited balance sheet filed in the 2008 Form 10-K. The Company has evaluated events or transactions through August 5, 2009 in conjunction with its preparation of these financial statements.

The preparation of financial statements in conformity with U. S. GAAP 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 that may be expected for any other interim period or for the entire year.

Inventory

Inventories are stated at the lower of cost or market. Inventory consists of the following (in thousands):

	June 30, 2009	December 31, 2008
Tubular goods and equipment	$ 15,756	$ 14,884
Crude oil	24,402	7,326
	$ 40,158	$ 22,210

Crude oil represents 669,000 barrels of crude oil at June 30, 2009 and 275,000 barrels of crude oil at December 31, 2008. The Company has entered into a series of physical delivery forward sale contracts that provide for the sale of stored crude oil in future months. The Company is currently scheduled to sell 248,200 barrels of currently stored crude oil to be delivered in the second half of 2009. Minimum pipeline line fill requirements resulted in inventory balances of 341,000 barrels and 230,000 barrels at June 30, 2009 and December 31, 2008, respectively, that were not currently available for sale.

Earnings (loss) per common share

Basic earnings per common share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution of non-vested restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if these options were exercised. The following is the calculation of basic and diluted weighted average shares outstanding and income (loss) per share computations for the three and six months ended June 30, 2009 and 2008:

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	Three months ended June 30, 2009	2008	Six months ended June 30, 2009	2008
	(in thousands, except per share data)			
Income (loss) (numerator):				
Net income (loss) - basic and diluted	$ 13,508	$ 127,307	$ (13,105)	$ 215,278
Weighted average shares (denominator):				
Weighted average shares - basic	168,492	168,055	168,479	167,973
Restricted shares	584	643		738
Employee stock options	422	854		707
Weighted average shares - diluted	169,498	169,552	168,479	169,418
Income (loss) per share:				
Basic	$ 0.08	$ 0.76	$ (0.08)	$ 1.28
Diluted	$ 0.08	$ 0.75	$ (0.08)	$ 1.27

The potential dilutive effect of 455,000 weighted average restricted shares and 421,000 weighted average stock options were not considered in diluted income (loss) per share for the six months ended June 30, 2009, because to do so would have been anti-dilutive.

New accounting standards

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (SFAS 160). SFAS 141(R) changes how business acquisitions are accounted for and impacts financial statements both on the acquisition date and in subsequent periods. SFAS 160 changes the accounting and reporting for minority interests, which are re-characterized as noncontrolling interests and classified as a component of equity. SFAS 141(R) and SFAS 160 are effective for the Company for fiscal years beginning on or after December 15, 2008. SFAS 141(R) will be applied prospectively. SFAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of SFAS 160 will be applied prospectively. The adoption of SFAS 141(R) and SFAS 160 on January 1, 2009 did not have any impact on the Company s financial position or results of operations though it would impact financial reporting for any future acquisitions.

In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-2, *Effective Date of FASB Statement No. 157,* which provided a one year delay of the effective date of FAS 157 to January 1, 2009 for the Company for non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Beginning January 1, 2009, the Company applied SFAS No. 157 to non-financial assets and liabilities. SFAS No. 157 applies to the Company s non-financial assets and liabilities in calculating fair value related to impairments of long-lived assets and asset retirement obligations. In both cases, SFAS No. 157 had no effect on these calculations. Both calculations are based primarily on level three inputs. The adoption of SFAS No. 157 did not have a material impact on the Company s financial position or results of operations.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities-An amendment of FASB Statement No. 133,* which amends and expands the disclosure requirements of FAS 133 to require qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The Company adopted the disclosure requirements of SFAS No. 161 beginning January 1, 2009. The adoption of this statement did not have an impact on the Company s financial position or results of operations.

In April 2009, the FASB issued two FSPs to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities.

FSP FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly,* (FSP FAS 157-4) provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157. It also includes guidance on identifying circumstances that indicate a transaction is not orderly. The Company adopted FSP FAS 157-4 for the period ended June 30, 2009 and the adoption of this FSP did not have an impact on its financial position or results of operations.

FSP FAS 107-1 and APB 28-1, *Interim Disclosures about Fair Value of Financial Instruments*, (FSP FAS 107-1) requires that disclosures concerning the fair value of financial instruments be presented in interim as well as annual financial statements, which enhances consistency in financial reporting. The Company adopted the provisions of FSP FAS 107-1 for the period ended June 30, 2009. The adoption of FSP FAS 107-1 did not have an impact on its financial position or results of operations.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (SFAS No. 165). SFAS No. 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Although there is new terminology, the standard is based on the same principles as those that currently exist. This statement, which includes a new required disclosure of the date through which an entity has evaluated subsequent events, is effective for interim or annual periods ending after June 15, 2009. The Company adopted SFAS No. 165 for the period ending June 30, 2009. The adoption of SFAS No. 165 did not have an impact on its financial position or results of operations.

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Note 3. Cash Flow Information

Net cash provided by operating activities reflects cash interest payments of $9.8 million for the six months ended June 30, 2009 and $5.8 million for the six months ended June 30, 2008. During the first quarter of 2009, the Company received cash payments of $1.9 million for refunds of income taxes paid. Non-cash investing and financing activities include asset retirement obligations of $0.6 million and $2.1 million for the six months ended June 30, 2009 and 2008, respectively.

Note 4. Derivative Contracts

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 elected not to designate its derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, the Company marked its derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value on derivative instruments in the statement of operations.

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 to partially reduce price risk. During each month of the contract, the Company received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. These contracts expired in April 2008 and currently the Company s crude oil production remains unhedged.

In June 2009, the Company entered into natural gas fixed price swaps for 600,000 MMBtu per month at an average price of $5.80 per MMBtu for December 2009 and $6.30 per MMBtu for calendar year 2010. The Company also entered into basis swaps for the same volumes and periods to lock in the difference between NYMEX natural gas prices and Inside FERC Centerpoint Energy East Index at an average differential of ($0.53) per MMBtu for December 2009 and ($0.62) for calendar year 2010. These swaps were put in place to underpin the Company s current and expected level of operations in the Arkoma Woodford play in southeastern Oklahoma by securing a predictable cash flow stream on about a third of the Company s natural gas production for the periods covered.

Derivative Fair Value Income (Loss)

The following table presents information about the components of derivative fair value income (loss) for the following periods presented:

(in thousands)	Three months ended June 30, 2009	Three months ended June 30, 2008	Six months ended June 30, 2009	Six months ended June 30, 2008
Realized gain (loss) on derivatives:				
Crude oil fixed price swaps	$	$ (11,869)	$	$ (34,669)
Unrealized gain (loss) on derivatives				
Crude oil fixed price swaps		8,511		26,703
Natural gas fixed price swaps	1,835		1,835	
Natural gas basis swaps	(945)		(945)	
Derivative fair value income (loss)	$ 890	$ (3,358)	$ 890	$ (7,966)

The Company adopted SFAS No. 161 in January 2009 and the expanded disclosures required are presented below. The table below provides data about the carrying values of derivatives that do not qualify for hedge accounting.

(in thousands)	June 30, 2009 Assets Carrying Value	June 30, 2009 (Liabilities) Carrying Value	June 30, 2009 Net Carrying Value	December 31, 2008 Assets Carrying Value	December 31, 2008 (Liabilities) Carrying Value	December 31, 2008 Net Carrying Value
Derivative that do not qualify for hedge accounting:						
Fixed price swaps	$ 1,835	$	$ 1,835	$	$	$
Basis swaps		(945)	(945)			

$ 1,835	$ (945)	$ 890	$	$	$

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Note 5. Fair Value Measures

SFAS No. 157 establishes a fair value hierarchy which prioritizes the input to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. The Company uses Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Under SFAS No.157, certain assets and liabilities are reported at fair value on a recurring basis. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. In determining the fair value of its fixed price and basis swaps, due to the unavailability of relevant comparable market data for our exact contracts, a discounted cash flow method is used. The discounted cash flow method estimates future cash flows based on quoted market prices for future commodity prices, observable inputs relating to basis differentials and a risk-adjusted discount rate. The fair value of derivatives is calculated using mainly significant observable inputs (Level 2).The Company s calculation is then compared to the counterparty valuation for reasonableness. The following table summarizes the valuation of investments and financial instruments by SFAS No. 157 pricing levels as of June 30, 2009:

	Fair value measurements using			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
		(In thousands)		
Derivatives:				
Fixed price swaps	$	$ 1,835	$	$ 1,835
Basis swaps	$	$ (945)	$	$ (945)

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Asset Impairments In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* proved oil and gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. The estimated future cash flows expected in connection with the property are compared to the carrying amount of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used. The discounted cash flow method estimates future cash flows based on management s expectations for the future and includes estimates of future oil and gas production, commodity prices based on commodity futures price strips, operating and development costs, and a risk-adjusted discount rate. The fair value of oil and gas properties is calculated using significant unobservable inputs (Level 3).

As a result of changes in reserves and the forward futures price strip, developed oil and gas properties were reviewed for impairment at June 30, 2009. The Company determined that the carrying amount of certain fields were not recoverable from future cash flows and, therefore, were impaired at June 30, 2009. The affected fields had a fair value of $1.8 million at June 30, 2009 resulting in $10.1 million of developed property impairments for the quarter ended June 30, 2009. A similar calculation at March 31, 2009 determined that the carrying amount of certain fields was not recoverable from future cash flows and, therefore, was impaired. The affected fields at March 31, 2009 had a fair value of $13.1 million resulting in $26.0 million of developed property impairments for first quarter of 2009. Total pre-tax (non-cash) impairments related to developed oil and gas properties for first half of 2009 were $36.1 million.

Asset Retirement Obligations The fair value of asset retirement obligations AROs is estimated based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. The fair value of ARO additions for the six months ended June 30, 2009 was $723,000. The fair value of ARO is calculated using significant unobservable inputs (Level 3).

Note 6. Long-term Debt

The Company had $592.0 million and $376.4 million in long-term debt outstanding at June 30, 2009 and December 31, 2008, respectively, on its revolving credit facility due April 11, 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

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Interbank Offered Rate for one, two, three or six months, as elected by the Company, plus a margin ranging from 175 to 250 basis points, depending on the percentage of its borrowing base utilized, or the lead bank s reference rate. The revolving credit facility has a maximum facility amount of $750.0 million and a borrowing base of $850.0 million, subject to semi-annual re-determination. The commitment level was increased from $672.5 million to $750.0 million on June 25, 2009. Under the terms of the revolving credit facility, the commitment level can be increased up to the lesser of the borrowing base or the note amount subject to bank agreement. The Company s weighted average interest rate was 2.60% at June 30, 2009. Amounts outstanding under the revolving credit facility at June 30, 2009 are stated at cost, which approximates fair value.

The Company had $158.0 million of unused commitments under the revolving credit facility at June 30, 2009 and incurs commitment fees of 0.25% to 0.375% of the daily average excess of the commitment amount over the outstanding credit balance. The revolving 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 revolving credit facility) and a Total Funded Debt to EBITDAX, as such terms are defined in the credit agreement, of no greater than 3.75 to 1.0. The Company was in compliance with these covenants at June 30, 2009.

Note 7. Commitments and Contingencies

Drilling Commitments. As of June 30, 2009, the Company had one drilling contract that expires in August 2011. This commitment is not recorded in the accompanying consolidated balance sheets. Future commitments as of June 30, 2009 are $19.1 million for the contract expiring in 2011.

Employee retirement plan. The Company maintains a defined contribution retirement plan for its employees and makes discretionary contributions to the plan based on a percentage of each eligible employee s compensation. During the first half of 2009 and the year ended December 31, 2008, contributions to the plan were 5% of eligible employees compensation, excluding bonuses.

Employee health claims. The Company self insures employee health claims up to the first $125,000 per employee. The Company self insures employee workers compensation claims up to the first $250,000 per employee. Any amounts paid above these are reinsured through third-party providers. The Company accrues for claims that have been incurred but not yet reported based on a review of claims filed versus expected claims based on claims history. At June 30, 2009 and December 31, 2008, the accrued liability for health and worker s compensation claims was $1.1 million and $0.9 million, respectively.

Litigation. The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will individually or collectively have a material adverse effect on the financial position or results of operations of the Company. As of June 30, 2009 and December 31, 2008, the Company has provided a reserve of $2.7 million and $1.2 million, respectively, for various matters none of which are believed to be individually significant.

Environmental Risk. 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

The Company has granted stock options and restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2000 Stock Option Plan (2000 Plan) and the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan) as discussed below. The Company s associated compensation expense included in general and administrative expense was $5.4 million for the six months ended June 30, 2009 and $3.9 million for the six months ended June 30, 2008.

Stock Options

Effective October 1, 2000, the Company adopted the 2000 Plan and granted options to eligible employees. These grants consisted of either incentive stock options, nonqualified stock options or a combination of both. The granted stock options vest ratably over either a three or five-year period commencing on the first anniversary of the grant date and expire ten years from date of grant. On November 10, 2005, the 2000 Plan was terminated. As of June 30, 2009, options covering 1,870,463 shares had been exercised.

The Company s stock option activity under the 2000 Plan for the six months ended June 30, 2009 was as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding December 31, 2008	450,200	$ 1.28	450,200	$ 1.28
Exercised	(7,000)	0.71	(7,000)	0.71
Outstanding June 30, 2009	443,200	1.29	443,200	1.29

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 at its exercise date. The total intrinsic value of options exercised during the six months ended June 30, 2009 was approximately $97,000. At June 30, 2009, all options were exercisable and had a weighted average life of 1.3 years with an aggregate intrinsic value of $11.7 million.

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Restricted Stock

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of June 30, 2009, the Company had 3,521,962 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 changes in the non-vested shares of restricted stock for the six months ended June 30, 2009, is presented below:

	Unvested restricted Shares	Weighted average grant-date fair value
Unvested restricted shares at December 31, 2008	1,110,892	$ 24.05
Granted	109,496	24.72
Vested	(62,260)	27.59
Forfeited	(24,004)	21.70
Outstanding June 30, 2009	1,134,124	23.97

The fair value of the restricted shares that vested during the six months ended June 30, 2009 at their vesting date was $1.5 million. As of June 30, 2009, there was $13.9 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.27 years.

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Cautionary Statement Regarding Forward-Looking Statements

Certain statements and information in this report may constitute forward-looking statements within the meaning of the Private Securities Litigation Act of 1995. The words believe, expect, anticipate, plan, intend, foresee, should, would, could or other similar express intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we currently anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those summarized below:

- business strategy;
- reserves;
- technology;
- financial strategy;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;
- competition and government regulations;
- marketing of oil and natural gas;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;

- credit markets;
- liquidity and access to capital;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

Other factors that could cause our actual results to differ from our projected results are described in (1) our Annual Report on Form 10-K for the fiscal year ended December 31, 2008, (2) our reports and registration statements filed from time to time with the SEC and (3) other announcements we make from time to time. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our historical consolidated financial statements and the notes included in our Annual Report on Form 10-K for the year ended December 31, 2008. Our operating results for the periods discussed may not be indicative of future performance. Statements concerning future results are forward-looking statements.

Overview

We are engaged in oil and natural gas exploration, exploitation and production activities in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We target large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. We derive the majority of 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 product prices and our ability to increase our oil and natural gas production. In recent months and years, there has been significant volatility in oil and natural gas prices due to a variety of factors we can not control or predict, including political and economic events, weather conditions, and competition from other energy sources. These factors impact supply and demand for oil and natural gas, which affects oil and natural gas prices. In addition, the prices we realize for our oil and natural gas production are affected by location differences in market prices. Oil and natural gas prices have declined dramatically over the past year and have made a material impact on our operating results as we discuss in detail below.

For the first six months of 2009, our oil and natural gas production increased to 6,711 MBoe (37,079 Boe per day), up 19% from the first six months of 2008. The increase in 2009 production was primarily driven by an increase in production from our Arkoma Woodford and Bakken fields. Despite this substantial increase in production, our oil and natural gas revenues for the first six months of 2009 decreased by 54% to $239.0 million due to a 60% decrease in commodity prices compared to the same period in 2008. Our realized price per Boe decreased $55.35 to $36.99 for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. While we experienced decreases in production expense and production tax and other expenses of a combined total of $15.6 million, or 19%, due to a decrease in workover expense and a decrease in production taxes as a result of lower commodity prices, respectively, our decrease in combined per unit cost was $4.16 per Boe, or 29%, as a result of a 796 MBoe increase in sales volumes. For the six months ended June 30, 2009, oil sales volumes were 251 MBbls less than oil production due to temporary storage of barrels in response to low prices and pipeline line fill requirements. Oil sales volumes were 35 MBbls more than production for the same period in 2008 due to the sale of crude oil inventory. Our cash flow from operating activities for the six months ended June 30, 2009, was $82.5 million, a decrease of $215.5 million from $298.0 million provided by our operating activities during the comparable 2008 period. The decrease in operating cash flows was primarily due to decreases in commodity prices. During the six months ended June 30, 2009, we invested $227.4 million (excluding payments to reduce accruals of $71.1 million and including seismic costs) in our capital program concentrating mainly in the Red River units, the Bakken field and the Arkoma Woodford play.

In response to significantly lower oil and natural gas prices during the fourth quarter of 2008 and the first three months of 2009 and the resulting decrease in cash flows, we significantly reduced our capital expenditures budget for 2009 to $275 million. Due to drilling rig commitments and in-progress drilling operations, we knew these expenditures would be heavily weighted toward the first quarter of 2009. Based on increased crude oil prices in the second quarter of 2009 Continental has increased its 2009 capital expenditures budget by 42% from the previously announced budget to $390 million, with the majority of the additional spending directed at drilling operations in the North Dakota Bakken. Even though capital expenditures for the six months ended June 30, 2009 exceeded cash flow from operations, we still expect to manage our capital expenditures for the year to be inline with our cash flows from operations. To the extent commodity price changes cause us to generate insufficient cash flow to finance this budget, we may decrease our actual capital expenditures during 2009 or increase debt.

How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance. Among these measures are:

- volumes of oil and natural gas produced,

- oil and natural gas prices realized,

- per unit operating and administrative costs, and

- EBITDAX.

The following table contains financial and operational highlights for the periods presented.

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	Three months ended June 30, 2009	2008	Six months ended June 30, 2009	2008
Average daily production:				
Oil (Bbl)	27,654	24,117	27,119	24,080
Natural gas (Mcf)	58,156	45,035	59,760	41,098
Oil equivalents (Boe)	37,347	31,623	37,079	30,930
Average prices: (1)				
Oil ($/Bbl)	$ 53.44	$ 118.28	$ 44.82	$ 104.43
Natural gas ($/Mcf)	2.60	8.82	2.79	8.25
Oil equivalents ($/Boe)	43.52	102.86	36.99	92.34
Production expense ($/Boe) (1)	7.14	9.32	7.19	8.83
General and administrative expense ($/Boe) (1)	2.78	3.55	3.04	3.14
EBITDAX (in thousands) (2)	106,250	244,950	163,923	426,738
Net income (loss) (in thousands)	13,508	127,307	(13,105)	215,278
Diluted net income (loss) per share	0.08	0.75	(0.08)	1.27

(1) Oil sales volumes were 35 MBbls less than oil production for the three months ended June 30, 2009 and 16 MBbls more than oil production for the three months ended June 30, 2008. For the six months ended June 30, 2009 oil sales volumes were 251 MBbls less than oil production and 35 MBbls more than oil production for the six months ended June 30, 2008. Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions.

(2) EBITDAX represents earnings before interest expense, income taxes, 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 U. S. GAAP. A reconciliation of net income to EBITDAX is provided subsequently under the header Non-GAAP Financial Measures.

Three months ended June 30, 2009 compared to the three months ended June 30, 2008

Results of Operations

The following table presents selected financial and operating information for each of the periods presented.

(in thousands, except volume price data)	Three months ended June 30, 2009	2008
Oil and natural gas sales	$ 146,439	$ 297,619
Derivatives gain (loss)	890	(3,358)
Total revenues	151,761	303,434
Operating costs and expenses	125,580	98,205
Other expense	4,422	2,617
Net income, before income taxes	21,759	202,612
Provision for income taxes	8,251	75,305
Net income	$ 13,508	$ 127,307
Production Volumes:		
Oil (MBbl)	2,517	2,195
Natural gas (MMcf)	5,293	4,098
Oil equivalents (MBoe)	3,398	2,878
Sales Volumes:		
Oil (MBbl)	2,482	2,211
Natural gas (MMcf)	5,293	4,098
Oil equivalents (MBoe)	3,365	2,894
Average Prices: (1)		
Oil ($/Bbl)	$ 53.44	$ 118.28
Natural gas ($/Mcf)	$ 2.60	$ 8.82

Oil equivalents ($/Boe)	$	43.52	$	102.86

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

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Production

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

	Three months ended June 30, 2009 Volume	2009 Percent	2008 Volume	2008 Percent	Volume Increase	Percent Increase
Oil (MBbl)	2,517	74%	2,195	76%	322	15%
Natural Gas (MMcf)	5,293	26%	4,098	24%	1,195	29%
Total (MBoe)	3,398	100%	2,878	100%	520	18%

	Three months ended June 30, 2009 MBoe	2009 Percent	2008 MBoe	2008 Percent	Volume increase (decrease)	Percent increase (decrease)
Rocky Mountain	2,585	76%	2,228	77%	357	16%
Mid-Continent	766	23%	595	21%	171	29%
Gulf Coast	47	1%	55	2%	(8)	(15)%
Total (MBoe)	3,398	100%	2,878	100%	520	18%

Oil production volumes increased 15% during the three months ended June 30, 2009 compared to the three months ended June 30, 2008. Production increases in the Bakken field and the Red River units contributed incremental volumes in 2009 of 371 MBbls in excess of production for the second quarter of 2008. Favorable results from drilling have been the primary contributors to production growth in these areas. This increase was partially offset by decreases in other areas, most notably a 34 MBbl decrease in the Rockies Other area. Natural gas volumes increased 1,195 MMcf, or 29%, during the three months ended June 30, 2009 compared to the same period in 2008. The majority of the increase, 1.1 Bcf, was from the Mid-Continent region due to the results of our exploration efforts in the Arkoma Woodford play. The Rocky Mountain region natural gas production was up 125 MMcf for the three months ended June 30, 2009 compared to the same period in 2008 due to additional natural gas being connected and sold in North Dakota.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the three months ended June 30, 2009 were $146.4 million, a 51% decrease from sales of $297.6 million for the same period in 2008. Our sales volumes increased 471 MBoe or 16% over the same period in 2008 volumes due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe decreased $59.33 to $43.52 for the three months ended June 30, 2009 from $102.86 for the three months ended June 30, 2008. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended June 30, 2009 was $6.02 compared to $5.75 for the three months ended June 30, 2008, $8.32 for the first quarter 2009, and $9.50 for the year ended December 31, 2008. Factors contributing to the changing differentials included Canadian oil imports and increases in production in the Rocky Mountain region, coupled with downstream transportation capacity constraints, refinery downtime in the Rocky Mountain region, and seasonal demand fluctuations for gasoline.

Derivatives. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value on derivative instruments in the statement of operations under the caption Gain (loss) on mark-to-market derivative instruments.

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 to partially reduce price risk. During each month of the contract, we received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. These contracts expired in April 2008 and during the three months ended June 30, 2008 we had recognized losses on derivatives of $3.4 million. Currently our crude oil production remains unhedged.

In June 2009, we entered into natural gas fixed price swaps for 600,000 MMBtu per month at an average price of $5.80 per MMBtu for December 2009 and $6.30 per MMBtu for calendar year 2010. We also entered into basis swaps for the same volumes and periods to lock in the difference between NYMEX natural gas prices and Inside FERC Centerpoint Energy East Index at an average differential of ($0.53) per MMBtu for December 2009 and ($0.62) for calendar year 2010. These swaps were put in place to underpin our current and expected level of operations in the Arkoma Woodford play in southeastern Oklahoma by securing a predictable cash flow stream on about a third of our natural gas production for the periods covered. We reported non-cash unrealized mark-to-market gains from our gas derivatives of $890,000 for the three months ended June 30, 2009.

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. Prices for reclaimed oil sold from our central treating unit were lower

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for the three months ended June 30, 2009 than the comparable 2008 period. The price decreased $56.01 per barrel which decreased reclaimed oil income by $4.5 million contributing to an overall decrease in oil and gas service operations revenue of $4.7 million for the three months ended June 30, 2009. Associated oil and natural gas service operations expenses decreased $3.8 million to $2.7 million during the three months ended June 30, 2009 from $6.5 million during the three months ended June 30, 2008 due mainly to a decrease in the costs of purchasing and treating oil for resale compared to the same period in 2008. We sold high-pressure air from our Red River units to a third party and recorded revenues of $0.4 million for the three months ended June 30, 2009 compared to $0.8 million for the three months ended June 30, 2008.

Operating Costs and Expenses

Production Expense and Production Tax and Other Expenses. Production expense decreased $3.0 million, or 11%, during the three months ended June 30, 2009 to $24.0 million from $27.0 million during the three months ended June 30, 2008. During the three months ended June 30, 2009, we participated in the completion of 50 gross (14.2 net) wells. Production expense per Boe decreased to $7.14 for the three months ended June 30, 2009 from $9.32 per Boe for the three months ended June 30, 2008 due to a decrease in workover expenses coupled with an increase in sales volumes.

Production tax and other expenses decreased $6.1 million, or 34%, during the three months ended June 30, 2009 compared to the three months ended June 30, 2008 as a result of lower revenues resulting from decreased sales prices partially offset by the expiration of various tax incentives and increases in other charges. Production tax and other expenses on the unaudited condensed consolidated statements of operations includes other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma area of $2.3 million and $0.5 million for the three months ended June 30, 2009 and 2008, respectively. Production tax, excluding other charges, as a percentage of oil and natural gas sales was 6.4% for the three months ended June 30, 2009 compared to 5.9% for the three months ended June 30, 2008. 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 natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, North Dakota and Oklahoma, new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rates. Our overall production tax rate is expected to increase as incentives we currently receive for horizontal wells reach the end of their incentive period.

On a unit of sales basis, production expense and production tax and other expenses were as follows:

($/Boe)	Three months ended June 30, 2009	Three months ended June 30, 2008	Percent Decrease
Production expense	$ 7.14	$ 9.32	(23%)
Production tax and other expenses	3.46	6.12	(43%)
Production expense, production tax and other expenses	$ 10.60	$ 15.44	(31%)

Exploration Expense. Exploration expense consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expense decreased $4.2 million in the three months ended June 30, 2009 to $1.5 million due primarily to a decrease in seismic expense of $3.3 million to $0.3 million and a decrease in dry hole expense of $1.1 million.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $25.1 million in the second quarter of 2009 compared to the second quarter of 2008, primarily due to an increase in oil and natural gas DD&A of $24.9 million as a result of increased production and additional properties with higher cost reserves being added through our drilling program. Additionally, DD&A increased as a result of the decrease in commodity prices used to calculate year end 2008 reserves volumes. Lower prices have the effect of decreasing the economic life of oil and natural gas properties, which lowers future reserve volumes and increases DD&A. The following table shows the components of our DD&A rate per Boe.

($/Boe)	Three months ended June 30, 2009	Three months ended June 30, 2008
Oil and natural gas	$ 15.40	$ 9.33
Other equipment	0.23	0.20
Asset retirement obligation accretion	0.17	0.17

Depreciation, depletion, amortization and accretion	$ 15.80	$ 9.70

Property Impairments. Property impairments, non-producing and developed, increased in the three months ended June 30, 2009 by $20.1 million to $23.3 million compared to $3.2 million during the three months ended June 30, 2008. Impairment of non-producing properties increased $10.5 million during the three months ended June 30, 2009 to $13.2 million compared to $2.7 million for the three months ended June 30, 2008 reflecting higher amortization of leasehold costs in our existing fields resulting from further defining likely drilling locations, capital constraints, and amortization of new fields. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

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Impairment provisions for developed oil and gas properties were approximately $10.1 million for the three months ended June 30, 2009 compared to approximately $0.4 million for the three months ended June 30, 2008, an increase of $9.7 million. We evaluate our developed oil and gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then we impair it based on an estimate of fair market value based on discounted cash flows. The majority of the impairment in 2009 reflects uneconomic drilling results in our Mid-Continent region which resulted in impairments of $10.0 million for the three months ended June 30, 2009. The remaining impairment is the result of decreases in reserves and prices.

General and Administrative Expense. General and administrative expense decreased $0.9 million to $9.4 million during the three months ended June 30, 2009 from $10.3 million during the comparable period of 2008. General and administrative expense includes non-cash charges for stock-based compensation of $2.7 million and $2.5 million for the three months ended June 30, 2009 and 2008, respectively. General and administrative expense excluding equity compensation decreased $1.1 million for the three months ended June 30, 2009 compared to the three months ended June 30, 2008. The decrease was primarily related to a donation of $1.0 million made in 2008 to Oklahoma State University to support a petroleum engineering program that was not repeated in 2009. On a volumetric basis, general and administrative expense decreased $0.77 to $2.78 per Boe for the three months ended June 30, 2009 compared to $3.55 per Boe for the three months ended June 30, 2008.

Interest Expense. Interest expense increased 65%, or $1.9 million, for the three months ended June 30, 2009 compared to the three months ended June 30, 2008, due to higher debt balances. Our average debt balance increased to $612.6 million for the three months ended June 30, 2009 compared to $241.3 million for the three months ended June 30, 2008, but the weighted average interest rate on our revolving credit facility was lower at 2.72% for the three months ended June 30, 2009 compared to 4.40% for the same period in 2008. As described in greater detail below (see Liquidity and Capital Resources) a significant portion of the increased borrowings were used to pay for capital expenditures incurred during the first quarter of 2009 that could not be funded from cash flows from operations due to the significant decrease in commodity prices. At July 31, 2009 our outstanding debt balance was $572.0 million with a weighted average interest rate of 2.57%.

Income Taxes. We recorded income tax expense for the three months ended June 30, 2009 of $8.3 million compared to $75.3 million for the three months ended June 30, 2008. We provide taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

Six months ended June 30, 2009 compared to the six months ended June 30, 2008

Results of Operations

The following table presents selected financial and operating information for each of the periods presented.

	Six months ended June 30,	
(in thousands, except volume price data)	**2009**	**2008**
Oil and natural gas sales	$ 239,007	$ 523,044
Derivatives gain (loss)	890	(7,966)
Total revenues	248,369	531,085
Operating costs and expenses	260,620	184,163
Other expense	8,862	5,729
Net income (loss), before income taxes	(21,113)	341,193
Provision (benefit) for income taxes	(8,008)	125,915
Net (loss) income	$ (13,105)	$ 215,278
Production Volumes:		
Oil (MBbl)	4,909	4,383
Natural gas (MMcf)	10,817	7,480
Oil equivalents (MBoe)	6,711	5,629
Sales Volumes:		
Oil (MBbl)	4,658	4,418
Natural gas (MMcf)	10,817	7,480
Oil equivalents (MBoe)	6,461	5,665
Average Prices: (1)		

Oil ($/Bbl)	$ 44.82	$ 104.43
Natural gas ($/Mcf)	$ 2.79	$ 8.25
Oil equivalents ($/Boe)	$ 36.99	$ 92.34

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

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Production

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

	Six months ended June 30,					
	2009		2008		Volume	Percent
	Volume	Percent	Volume	Percent	increase	increase
Oil (MBbl)	4,909	73%	4,383	78%	526	12%
Natural Gas (MMcf)	10,817	27%	7,480	22%	3,337	45%
Total (MBoe)	6,711	100%	5,629	100%	1,082	19%

	Six months ended June 30,				Volume	Percent
	2009		2008		increase	increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
Rocky Mountain	5,027	75%	4,402	78%	625	14%
Mid-Continent	1,580	24%	1,117	20%	463	41%
Gulf Coast	104	1%	110	2%	(6)	(5)%
Total (MBoe)	6,711	100%	5,629	100%	1,082	19%

Oil production volumes increased 12% during the six months ended June 30, 2009 compared to the six months ended June 30, 2008. Production increases in the Bakken field area contributed incremental volumes in excess of production for the same period in 2008 of 568 MBbls. Favorable results from drilling have been the primary contributors to production growth. This increase was partially offset by decreases in other areas, most notably a 39 MBbl decrease in the Rockies Other area. Natural gas volumes increased 3,337 MMcf, or 45%, during the three months ended June 30, 2009 compared to the same period in 2008. The majority of the increase, 2.8 Bcf, was from the Mid-Continent region due to the results of our exploration efforts in the Arkoma Woodford play. The Rocky Mountain region natural gas production was up 494 MMcf for the six months ended June 30, 2009 compared to the same period in 2008 due to additional natural gas being connected and sold in North Dakota.

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales for the six months ended June 30, 2009 were $239.0 million, a 54% decrease from sales of $523.0 million for the same period in 2008. Our sales volumes increased 796 MBoe or 14% over the same period in 2008 volumes due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe decreased $55.35 to $36.99 for the six months ended June 30, 2009 from $92.34 for the six months ended June 30, 2008. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the six months ended June 30, 2009 was $7.08 compared to $6.58 for the six months ended June 30, 2008 and $9.50 for the year ended December 31, 2008. Factors contributing to the changing differentials included Canadian oil imports and increases in production in the Rocky Mountain region, coupled with downstream transportation capacity constraints, refinery downtime in the Rocky Mountain region, and reduced seasonal demand for gasoline.

Derivatives. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* requires recognition of all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We elected not to designate our derivatives as cash flow hedges under the provisions of SFAS No. 133. As a result, we marked our derivative instruments to fair value in accordance with the provisions of SFAS No. 133 and recognized the realized and unrealized change in fair value on derivative instruments in the statement of operations under the caption Gain (loss) on mark-to-market derivative instruments.

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 to partially reduce price risk. During each month of the contract, we received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. These contracts expired in April 2008 and during the six months ended June 30, 2008 we had recognized losses on derivatives of $8.0 million. Currently our crude oil production remains unhedged.

In June 2009, we entered into natural gas fixed price swaps for 600,000 MMBtu per month at an average price of $5.80 per MMBtu for December 2009 and $6.30 per MMBtu for calendar year 2010. We also entered into basis swaps for the same volumes and periods to lock in the difference between NYMEX natural gas prices and Inside FERC Centerpoint Energy East Index at an average differential of ($0.53) per MMBtu for December 2009 and ($0.62) for calendar year 2010. These hedges were put in place to underpin our current and expected level of operations in the Arkoma Woodford play in southeastern Oklahoma by securing a predictable cash flow stream on about a third of our natural gas production for the periods covered. We reported non-cash unrealized mark-to-market gains from our gas derivatives of $890,000 for the six months ended June 30, 2009.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed oil and sales of high-pressure air . Prices for reclaimed oil sold from our central treating unit were lower for the six months ended June 30, 2009 than the comparable 2008 period. The price decreased $63.64 per barrel which

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decreased reclaimed oil income by $7.7 million contributing to an overall decrease in oil and gas service operations revenue of $7.5 million for the six months ended June 30, 2009. Associated oil and natural gas service operations expenses decreased $5.6 million to $5.1 million during the six months ended June 30, 2009 from $10.7 million during the six months ended June 30, 2008 due mainly to a decrease in the costs of purchasing and treating oil for resale compared to the same period in 2008. We sold high-pressure air from our Red River units to a third party and recorded revenues of $1.1 million and $1.5 million for the six months ended June 30, 2009 and 2008, respectively.

Operating Costs and Expenses

Production Expense, Production Tax and Other Expenses. Production expense decreased $3.5 million, or 7%, during the six months ended June 30, 2009 to $46.5 million from $50.0 million during the six months ended June 30, 2008. During the six months ended June 30, 2009, we participated in the completion of 129 gross (46.7 net) wells. Production expense per Boe decreased to $7.19 for the six months ended June 30, 2009 from $8.83 per Boe for the six months ended June 30, 2008 due to a decrease in workover expenses coupled with an increase in sales volumes. Production tax and other expenses decreased $12.0 million, or 39%, during the six months ended June 30, 2009 compared to the same period in 2008, as a result of lower revenues resulting from decreased sales prices partially offset by the expiration of various tax incentives and increases in other charges. Production tax and other expenses on the unaudited condensed consolidated statement of operations includes other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma area of $3.5 million and $1.0 million for the six months ended June 30, 2009 and 2008, respectively. Production tax, excluding other charges, as a percentage of oil and natural gas sales was 6.3% for the six months ended June 30, 2009 compared to 5.7% for the six months ended June 30, 2008. 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 natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, North Dakota and Oklahoma, new horizontal wells qualify for a tax incentive and are taxed at a lower rate during their initial months of production. After the incentive period expires, the tax rate increases to the statutory rates. Our overall production tax rate is expected to increase as incentives we currently receive for horizontal wells reach the end of their incentive period.

On a unit of sales basis, production expense and production tax and other expenses were as follows:

($/Boe)	Six months ended June 30, 2009	2008	Percent Decrease
Production expense	$ 7.19	$ 8.83	(19)%
Production tax and other expenses	2.86	5.38	(47)%
Production expense, production tax and other expenses	$ 10.05	$ 14.21	(29)%

Exploration Expense. Exploration expense consists primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expense decreased $2.3 million in the six months ended June 30, 2009 to $8.6 million due primarily to a decrease in seismic expense of $6.6 million to $1.2 million partially offset by an increase in dry hole expense of $3.3 million to $5.0 million. The majority of the dry hole costs were in the Mid-Continent region for the six months ended June 30, 2009 and were mostly attributable to three dry holes in Ohio ($3.8 million) and one non-operated North Dakota Bakken dry hole ($1.0 million).

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $47.1 million in the first half of 2009 compared to the first half of 2008, primarily due to an increase in oil and natural gas DD&A of $46.6 million as a result of increased production and additional properties with higher cost reserves being added through our drilling program. Additionally, DD&A increased as a result of the decrease in commodity prices used to calculate year end 2008 reserves volumes. Lower prices have the effect of decreasing the economic life of oil and natural gas properties, which lowers future reserve volumes and increases DD&A. The following table shows the components of our DD&A rate per Boe.

($/Boe)	Six months ended June 30, 2009	2008
Oil and natural gas	$ 15.66	$ 9.64
Other equipment	0.24	0.19
Asset retirement obligation accretion	0.17	0.18
Depreciation, depletion, amortization and accretion	$ 16.07	$ 10.01

Property Impairments. Property impairments, non-producing and developed, increased in the six months ended June 30, 2009 by $51.0 million to $58.7 million compared to $7.7 million during the six months ended June 30, 2008. Impairment of non-producing properties increased $16.7 million during the six months ended June 30, 2009 to $22.6 million compared to $5.9 million for the six months ended June 30, 2008 reflecting higher amortization of lease costs in our existing fields resulting from further defining likely drilling locations, capital constraints, and amortization of new fields. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

Impairment provisions for developed oil and gas properties were approximately $36.1 million for the six months ended June 30, 2009 compared to approximately $1.8 million for the six months ended June 30, 2008, an increase of $34.3 million. We evaluate our developed oil and gas properties for impairment by comparing their cost basis to the estimated future cash flows on a field basis. If the cost basis is in excess of estimated future cash flows, then we impair it based on an estimate of fair market value based on discounted cash flows. Impairments in 2009 reflect uneconomic drilling results in the first half of 2009 in our Mid-Continent region which resulted in impairments of $24.1 million for the six months ended June 30, 2009. The remaining impairments are the result of decreases in reserves and prices.

General and Administrative Expense. General and administrative expense increased $1.8 million to $19.6 million during the six months ended June 30, 2009 from $17.8 million during the comparable period of 2008. General and administrative expense includes non-cash charges for stock-based compensation of $5.4 million and $3.9 million for the six months ended June 30, 2009 and 2008, respectively. General and administrative expense excluding equity compensation increased $1.1 million for the six months ended June 30, 2009 compared to the six months ended June 30, 2008. The increase was primarily related to an increase in litigation expense of $0.8 million and an 8% increase in personnel costs due to higher salaries and benefits. These increases were partially offset by a donation of $1.0 million made in 2008 to Oklahoma State University to support a petroleum engineering program that was not repeated in 2009. On a volumetric basis, general and administrative expense decreased to $3.04 per Boe for the six months ended June 30, 2009 compared to $3.14 per Boe for the six months ended June 30, 2008 due to increased production volumes.

Interest Expense. Interest expense increased 48%, or $3.0 million, for the six months ended June 30, 2009 compared to the six months ended June 30, 2008, due to higher debt balances. Our average debt balance increased to $546.6 million for the six months ended June 30, 2009 compared to $224.5 million for the six months ended June 30, 2008, but the weighted average interest rate on our revolving credit facility was 3.07% for the six months ended June 30, 2009 compared to 5.04% for the same period in 2008. As described in greater detail below, a significant portion of the increased borrowings were used to pay for capital expenditures incurred during the fourth quarter of 2008 and the first three months of 2009 that could not be funded from cash flows from operations due to the significant decrease in commodity prices. At July 31, 2009 our outstanding debt balance was $572.0 million with a weighted average interest rate of 2.57%.

Income Taxes. We recorded an income tax benefit for the six months ended June 30, 2009 of $8.0 million compared to a $125.9 million expense for the six months ended June 30, 2008. We provide taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our revolving credit facility. As we exited the fourth quarter of 2008, oil and natural gas prices had declined significantly from their summer 2008 record levels which reduced our operational cash flows. In response, we began reducing capital expenditures during the last quarter of 2008 and prepared our capital expenditure budget for 2009 assuming lower commodity prices. However, realigning capital expenditures to reflect lower cash flows is not an instantaneous process; accordingly our debt has increased as operating activities and expenses were matched with the reduced level of cash flow.

Over the last year, problems in the credit markets, steep stock market declines, financial institution failures and government bail-outs signaled a weakened global economy. Recently the stock market has edged up and the credit markets appear to have stabilized. Our current revolving credit facility is backed by a syndicate of 15 banks. The banks reaffirmed our borrowing base of $850.0 million in June 2009 and we increased the commitment level to $750.0 million. One bank in our revolving credit facility may be unable to fulfill their remaining commitment ($16.6 million) under the revolving credit facility. We do not believe the loss of this one bank s remaining commitment would have any significant consequences. We believe that the rest of the syndicate banks currently have the capability to fund up to our current commitment. If one or more banks should not be able to do so, we may not have the full availability of the $750.0 million commitment. If the unsettled conditions, including substantial and sustained declines in commodity prices, continue for the long-term it may impact our ability to develop all of our projects.

During the second quarter of 2009, we saw increases in oil prices to levels double the first quarter lows. Oil accounts for more than 70% of our production. However, gas prices remain depressed. Overall, this has resulted in improved cash flow from operations and better liquidity. Additionally, we were able to increase our revolving credit facility commitment from $672.5 million to $750.0 million during the second quarter. As of June 30, 2009, we had $158.0 million available under our revolving credit facility and $22.8 million in working capital. During the first quarter of 2009, we had rig commitments on up to six rigs. We currently only have one rig committed through August 2011. Our current plan is to expand capital expenditures in a measured manner without long-term rig commitments. This will allow us to adapt rapidly to commodity price changes or other external factors. Based on increased crude oil prices, in August 2009, we increased our 2009 capital expenditures budget by 42% from the previously announced budget to $390 million, with the majority of the additional spending directed at drilling operations in the North Dakota Bakken. We are also seeing reductions in oil field service costs, including drilling costs compared to 2008.

We believe that funds from operating cash flows and the revolving 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.

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We currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. Furthermore, the issuance of additional debt may require that a portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

In the future, we may not be able to access adequate funding under our bank credit facilities as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base. The turmoil in the financial markets has adversely impacted the stability and solvency of a number of large global financial institutions.

The recent constraint on available credit has made it more difficult to obtain funding in the public and private capital markets. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the general stability of financial markets and the solvency of specific counterparties, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, imposed tighter lending standards, refused to refinance existing debt at maturity or on terms similar to existing debt or at all, and reduced and, in some cases, ceased to provide any new funding.

The current credit situation also has impacted the level of activity in the oil and natural gas property sales market. The lack of readily available credit and access to capital has limited and will likely continue to limit the parties interested in any proposed asset transactions and will likely reduce the values we could realize in those transactions, but may work in our favor in the event of an acquisition. As in the past, we will consider selling non-strategic assets in order to focus on our core projects if and when appropriate.

Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required and on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $82.5 million and $298.0 million for the six months ended June 30, 2009 and 2008, respectively. The decrease in operating cash flows was mainly due to decreases in revenue as a result of lower commodity prices as explained above.

Cash Flow from Investing Activities

During the six months ended June 30, 2009 and 2008 we had cash flows used in investing activities (excluding asset sales) of $297.2 million and $350.0 million, respectively, related to our capital program, inclusive of dry hole costs. The decrease in our cash flow used in investing activities was primarily due to more funding for acquisitions in 2008 than in 2009.

Cash Flow from Financing Activities

Net cash provided by financing activities of $213.1 million for the six months ended June 30, 2009 primarily represents amounts borrowed under our revolving credit facility to fund capital expenditures, including the reduction in accounts payable. Net cash provided by financing activities of $55.2 million for the six months ended June 30, 2008 was mainly the result of amounts borrowed under our revolving credit facility to fund capital expenditures, including acquisitions.

Credit Facility

We had $592.0 million and $376.4 million outstanding under our revolving credit facility at June 30, 2009 and December 31, 2008, respectively. The increase was largely due to borrowings to cover capital expenditures incurred in the fourth quarter of 2008 and the first quarter of 2009 that could not be funded from cash flow from operations due to the deterioration in oil and natural gas prices in the last half of 2008 and continuing into early 2009. The revolving credit facility currently has a borrowing base of $850.0 million, subject to semi-annual redetermination. We expect the next redetermination to occur in the fourth quarter of 2009. The terms of the revolving credit facility provide for the commitment level to be increased up to the lesser of the borrowing base or note amount subject to bank agreement. The commitment level was increased in June 2009 to $750.0 million, which equals the maximum note amount, from $672.5 million.

Capital Expenditures and Commitments

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. Acquisition expenditures are not budgeted.

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Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. In response to significantly lower oil and natural gas prices during the first three months of 2009 and the resulting decrease in expected cash flows, in early 2009 we reduced our capital expenditures budgeted for 2009 to $275.0 million. Based on increased crude oil prices, we have increased our 2009 capital expenditures budget by 42% to $390 million, with the majority of the additional spending directed at drilling operations in the North Dakota Bakken. Under our original $275 million capex budget for 2009, only one Company-operated rig would have been active from September through December 2009. The revised budget envisions the current total of four operated drilling rigs remaining active through September, with a fifth added in October, and a sixth in November. All of the additional rigs are planned to be added in the North Dakota Bakken, and the current single rig in the Arkoma will remain in place. In addition, we have reduced our rig count from 32 operated rigs in October 2008 to 4 operated rigs at June 30, 2009. We have one contract remaining on these rigs that expires in August 2011.

During the first six months of 2009, we participated in the completion of 129 gross (46.7 net) wells and invested a total of $227.4 million (excluding payments to reduce accruals of $71.1 million) for capital expenditures in 2009.

	Capital Expenditures	
(in millions)	**Budgeted for 2009**	**Actual six months ended June 30, 2009**
Exploration and development drilling	$ 294.8	$ 181.9
Acquisition of producing properties		0.4
Capital facilities, workovers and re-completions	37.0	13.9
Land costs	49.2	29.4
Seismic	2.1	1.2
Vehicles, computers and other equipment	6.9	0.6
Total	$ 390.0	$ 227.4

Even though capital expenditures for the six months ended June 30, 2009 exceeded cash flow from operations, we still expect to manage our capital expenditures for the year to be in line with our cash flows from operations. Although we recently increased our capital expenditures budget for 2009, we currently have budgeted for significantly lower capital expenditures throughout the remainder of 2009 compared to 2008. To the extent commodity price changes cause us to generate insufficient cash flow to finance this budget; we may decrease our actual capital expenditures during 2009. Conversely, a significant improvement in commodity prices could result in an increase in our actual capital expenditures during 2009.

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 revolving credit facility will be sufficient to satisfy our 2009 capital budget. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, available cash flow, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Recent Accounting Pronouncements Not Yet Adopted

On December 29, 2008, the SEC announced final approval of new requirements, effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves. The new disclosure requirements include:

- Consideration of new technologies in evaluating oil and natural gas reserves,

- Disclosure of probable and possible oil and natural gas reserves,

- Use of an average price based on the prior twelve month period rather than year-end prices, and

Revisions of the oil and natural gas disclosure requirements for operations.
We have not yet evaluated the effects of the above on our financial statements and disclosures.

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* (SFAS 168), which amends SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS 168 will become the source of authoritative U.S. GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date, SFAS 168 will supersede all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in SFAS 168 will become non-authoritative. SFAS 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company is currently assessing the impact SFAS 168 will have on its financial position or results of operations, but does not expect any impact from adoption of the pronouncement.

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Critical Accounting Policies

There has been no change in our critical accounting policies from those disclosed in our Form 10-K for the year ended December 31, 2008.

Non-GAAP Financial Measures

EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expense, unrealized derivative gains and losses, and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by U. S. GAAP. Management believes EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of its operations from period to period without regard to its financing methods or capital structure. We exclude the items listed above from net income in arriving at EBITDAX because these amounts can vary substantially from company to company within its industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. The credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. The following table is a reconciliation of our net income to EBITDAX.

	Three months ended June 30,		Six months ended June 30,	
	2009	2008	2009	2008
Net income (loss)	$ 13,508	$ 127,307	$ (13,105)	$ 215,278
Unrealized gain on derivative instruments	(890)		(890)	
Interest expense	4,723	2,865	9,310	6,276
Provision (benefit) for income taxes	8,251	75,305	(8,008)	125,915
Depreciation, depletion, amortization and accretion	53,148	28,062	103,845	56,708
Property impairments	23,275	3,153	58,700	7,673
Exploration expense	1,530	5,731	8,649	10,993
Equity compensation	2,705	2,527	5,422	3,895
EBITDAX	$ 106,250	$ 244,950	$ 163,923	$ 426,738

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

General

We are exposed to a variety of market risks including credit risk, 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.

Commodity Price Risk. Our primary market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control including volatility in the differences between product prices at sales points and the applicable index price. Based on our average daily production for the six months ended June 30, 2009, our annual revenue would increase or decrease by approximately $9.9 million for each $1.00 per barrel change in crude oil prices and $2.2 million for each $0.10 per MMBtu change in natural gas prices.

To partially reduce price risk caused by these market fluctuations, we have occasionally hedged crude oil and natural gas prices in the past, through the utilization of derivatives, including zero-cost collars and fixed price contracts. Most recently, in June 2009, we entered into natural gas fixed price swaps for 600,000 MMBtu at an average price of $5.80 per MMBtu for December 2009 and $6.30 per MMBtu for calendar year 2010. We also entered into basis swaps for the same volumes and periods to lock in the difference between NYMEX natural gas prices and

Inside FERC Centerpoint Energy East Index at an average differential of ($0.53) per MMBtu for December 2009 and ($0.62) for calendar year 2010. These swaps were put in place to underpin our current and expected level of operations in the Arkoma Woodford play in southeastern Oklahoma by securing a predictable cash flow stream on about a third of our natural gas production for the periods covered. As of June 30, 2009, we recorded an asset of $890,000 for unrealized gains and losses on derivatives.

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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 to partially reduce price risk. During each month of the contract, we received a fixed-price of $72.90 per barrel and paid to the counterparties the average of the prompt NYMEX crude oil futures contract settlement prices for such month. These contracts expired in April 2008 and during the six months ended June 30, 2008 we recognized losses on derivatives of $8.0 million. Currently, our crude oil production remains unhedged.

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 joint interest receivables ($72.5 million at June 30, 2009) and the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($104.5 million in receivables at June 30, 2009). Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We can do very little to choose who participates in our wells. In order to minimize our exposure to credit risk we request prepayment of drilling costs where it is allowed by contract or state law. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk. We also have the right to place a lien on our co-owners interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the lien. Historically, our credit losses on joint interest receivables have been immaterial.

We monitor our exposure to counterparties on oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. We have not generally required our counterparties to provide collateral to support oil and natural gas sales receivables owed to us.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility. We had total indebtedness of $572.0 million outstanding under our credit facility at July 31, 2009. The impact of a 1% increase in interest rates on this amount of debt would increase interest expense by approximately $5.7 million per year. Our long-term debt matures in 2011 and the weighted-average interest rate at July 31, 2009 was 2.57%.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Based on our management s evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, as of the end of the period covered by this report, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (which are defined in rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, (the Exchange Act) as controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within required time periods), were effective as of June 30, 2009. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2009, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that had materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Controls and Procedures

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Accordingly, even an effective system of internal control will provide only reasonable assurance that the objectives of the internal control system are met.

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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 currently involved in various legal proceedings which we do not expect to have a material adverse effect on our financial condition or results of operations.

ITEM 1A. Risk Factors

There has been no change in our risk factors from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2008 other than the addition of the following risk factors.

Proposed legislation under consideration by Congress could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business.

Our operations are subject to extensive federal, state and local regulations. Changes to existing regulations or new regulations may unfavorably impact us could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. For example, Congress is currently considering legislation that, if adopted in its current proposed form, would subject companies involved in oil and gas exploration and production activities to substantial additional regulation. If such legislation is adopted, it could result in, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of certain U.S. federal tax incentives and deductions available to oil and natural gas exploration and production companies, and the prohibition or additional regulation of private energy commodity derivative and hedging activities. These and other potential regulations could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. The purpose of ACESA is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. GHGs are certain gases, including carbon dioxide and methane that may be contributing to warming of the Earth s atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA s overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce.

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

(a) Not applicable.

(b) Not applicable.

(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

The following table provides information about purchases of equity securities that are registered by us pursuant to Section 12 of the Exchange Act during the quarter ended June 30, 2009:

Period	**(a) Total number of shares purchased**	**(b) Average price paid per share**	**(c) Total number of shares purchased as part of publicly announced plans or programs**	**(d) Maximum number of shares that may yet be purchased under the plans or program**
April 1, 2009 to April 30, 2009	4,838	$ 24.93		
May 1, 2009 to May 31, 2009	4,159	$ 27.21		
June 1, 2009 to June 30, 2009	2,080	$ 27.57		
Total	11,077	$ 26.28		

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In connection with stock option exercises or restricted stock grants under our 2000 Plan and our 2005 Plan, we adopted a policy that enables employees to surrender shares to cover their tax liability. See *Note 8.Stock Compensation* in Notes to Unaudited Condensed Consolidated Financial Statements. All shares purchased above represent shares surrendered to cover tax liabilities. We paid the associated taxes to the Internal Revenue Service.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

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

The Company held its Annual Meeting of Shareholders on May 28, 2009, for the purpose of electing three Directors of the Company each for a three year term and to ratify the appointment of Grant Thornton LLP to serve as the Company s independent registered public accounting firm for 2009. Holders of 163,756,674 shares (97.2% of total outstanding shares) voted in total.

Holders of 163,325,970shares voted for Robert J. Grant to serve as a Director of the Company for a period of three years, 430,704shares withheld authority. Holders of 155,961,722 shares voted for Mark E. Monroe to serve as a Director of the Company for a period of three years, 7,794,952 shares withheld authority. Holders of 163,321,098 shares voted for Ellis L. Lon McCain to serve as a Director of the Company for a period of three years, 435,576 shares withheld authority. Directors Hamm, Sanders, and Boren continue to serve as directors.

Holders of 163,679,090 shares voted for the proposal to ratify the appointment of Grant Thornton LLP to serve as the Company s independent registered public accounting firm for 2009, 57,458 shares voted against and 20,125 shares abstained. No broker non-votes were received.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

See the Index to Exhibits accompanying this report.

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SIGNATURE

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

	Continental Resources, Inc.
Date: August 6, 2009	By: /s/ John D. Hart John D. Hart Sr. Vice President, Chief Financial Officer and Treasurer (Duly Authorized Officer and Principal Financial Officer)

Index to Exhibits

The exhibits marked with the asterisk symbol (*) are filed or furnished (in the case of Exhibit 32) with this Form 10-Q.

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 (Commission File No. 001-328861) 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 (Commission File No. 001-328861) 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 (Commission File No. 001-328861) 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 (Commission File No. 333-132257) filed April 14, 2006 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).