CONTINENTAL RESOURCES INC
Form 10-Q
November 05, 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 September 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

169,855,461 shares of our $0.01 par value common stock were outstanding on October 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**

| | September 30, 2009 (Unaudited) | December 31, 2008 |
|---|---|---|
| | (In thousands, except share data) | |
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 5,295 | $ 5,229 |
| Receivables: | | |
| Oil and natural gas sales | 101,758 | 63,659 |
| Affiliated parties | 5,640 | 14,914 |
| Joint interest and other, net | 51,163 | 150,506 |
| Inventories | 35,248 | 22,210 |
| Deferred and prepaid taxes | 6,195 | 18,810 |
| Prepaid expenses and other | 3,225 | 2,367 |
| Total current assets | 208,524 | 277,695 |
| Net property and equipment, based on successful efforts method of accounting | 2,003,348 | 1,935,143 |
| Debt issuance costs, net | 11,177 | 3,041 |
| Total assets | $ 2,223,049 | $ 2,215,879 |
| **Liabilities and shareholders equity** | | |
| Current liabilities: | | |
| Accounts payable trade | $ 87,027 | $ 260,188 |
| Accounts payable trade to affiliated parties | 6,807 | 25,730 |
| Accrued liabilities and other | 32,238 | 34,769 |
| Revenues and royalties payable | 55,695 | 78,160 |
| Current portion of asset retirement obligation | 2,757 | 4,747 |
| Total current liabilities | 184,524 | 403,594 |
| Long-term debt | 546,305 | 376,400 |
| Other noncurrent liabilities: | | |
| Deferred tax liability | 466,843 | 445,752 |
| Asset retirement obligation, net of current portion | 43,681 | 39,883 |
| Other noncurrent liabilities | 3,143 | 1,542 |
| Total other noncurrent liabilities | 513,667 | 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, 169,911,440 shares issued and outstanding at September 30, 2009; 169,558,129 shares issued and outstanding at December 31, 2008 | 1,699 | 1,696 |
| Additional paid-in capital | 428,072 | 420,054 |
| Retained earnings | 548,782 | 526,958 |

| | | |
|---|---|---|
| Total shareholders equity | 978,553 | 948,708 |
| Total liabilities and shareholders equity | $ 2,223,049 | $ 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 Income**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2009 | 2008 | 2009 | 2008 |
| | (In thousands, except per share data) | | | |
| **Revenues:** | | | | |
| Oil and natural gas sales | $ 162,465 | $ 266,544 | $ 389,310 | $ 753,554 |
| Oil and natural gas sales to affiliates | 5,907 | 19,650 | 18,069 | 55,684 |
| Loss on mark-to-market derivative instruments | (2,105) | | (1,215) | (7,966) |
| Oil and natural gas service operations | 3,937 | 7,415 | 12,409 | 23,422 |
| Total revenues | 170,204 | 293,609 | 418,573 | 824,694 |
| **Operating costs and expenses:** | | | | |
| Production expenses | 17,536 | 18,886 | 56,269 | 60,704 |
| Production expense to affiliates | 5,183 | 6,361 | 12,914 | 14,569 |
| Production tax and other expenses | 12,378 | 17,941 | 30,829 | 48,411 |
| Exploration expense | 1,077 | 15,285 | 9,726 | 26,278 |
| Oil and natural gas service operations | 2,326 | 5,099 | 7,423 | 15,797 |
| Depreciation, depletion, amortization and accretion | 51,030 | 39,120 | 154,875 | 95,828 |
| Property impairments | 11,791 | 9,947 | 70,491 | 17,620 |
| General and administrative | 10,049 | 10,005 | 29,684 | 27,812 |
| Gain on sale of assets | (452) | (194) | (673) | (406) |
| Total operating costs and expenses | 110,918 | 122,450 | 371,538 | 306,613 |
| Income from operations | 59,286 | 171,159 | 47,035 | 518,081 |
| Other income (expense): | | | | |
| Interest expense | (4,763) | (2,506) | (14,073) | (8,782) |
| Other | 194 | 185 | 642 | 732 |
| | (4,569) | (2,321) | (13,431) | (8,050) |
| Income before income taxes | 54,717 | 168,838 | 33,604 | 510,031 |
| Provision for income taxes | 19,788 | 63,582 | 11,780 | 189,497 |
| Net income | $ 34,929 | $ 105,256 | $ 21,824 | $ 320,534 |
| Basic net income per share | $ 0.21 | $ 0.63 | $ 0.13 | $ 1.91 |
| Diluted net income per share | $ 0.21 | $ 0.62 | $ 0.13 | $ 1.89 |

*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 income (unaudited) | | | | 21,824 | 21,824 |
| Stock-based compensation (unaudited) | | | 8,594 | | 8,594 |
| Stock options: | | | | | |
| Exercised (unaudited) | 53,510 | | 141 | | 141 |
| Repurchased and canceled (unaudited) | (7,944) | | (284) | | (284) |
| Restricted stock: | | | | | |
| Issued (unaudited) | 348,123 | 3 | | | 3 |
| Repurchased and canceled (unaudited) | (16,374) | | (433) | | (433) |
| Forfeited (unaudited) | (24,004) | | | | |
| Balance, September 30, 2009 (unaudited) | 169,911,440 | $ 1,699 | $ 428,072 | $ 548,782 | $ 978,553 |

*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**

| | Nine months ended September 30, 2009 | 2008 |
|---|---|---|
| | (In thousands) | |
| **Cash flows from operating activities:** | | |
| Net income | $ 21,824 | $ 320,534 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion, amortization and accretion | 157,696 | 95,946 |
| Property impairments | 70,491 | 17,620 |
| Change in derivative fair value | 1,215 | (26,703) |
| Equity compensation | 8,594 | 6,479 |
| Tax benefit of excess non qualified stock option deduction | | (3,393) |
| Provision for deferred income taxes | 11,780 | 151,852 |
| Dry hole costs | 5,002 | 9,399 |
| Other, net | 1,053 | 174 |
| **Changes in assets and liabilities:** | | |
| Accounts receivable | 70,518 | (136,674) |
| Inventories | (13,038) | (14,899) |
| Prepaid expenses and other | 21,193 | 2,097 |
| Accounts payable | (115,194) | 108,612 |
| Revenues and royalties payable | (22,465) | 36,624 |
| Accrued liabilities and other | (4,275) | 22,076 |
| Other noncurrent liabilities | 1,601 | 188 |
| Net cash provided by operating activities | 215,995 | 589,932 |
| **Cash flows from investing activities:** | | |
| Exploration and development | (372,284) | (574,156) |
| Purchase of oil and gas properties | (1,217) | (74,514) |
| Purchase of other property and equipment | (4,682) | (13,638) |
| Proceeds from sale of assets | 2,762 | 2,192 |
| Net cash used in investing activities | (375,421) | (660,116) |
| **Cash flows from financing activities:** | | |
| Revolving credit facility | 372,100 | 268,000 |
| Repayment of revolving credit facility | (502,500) | (203,600) |
| Issuance of 8.25% Senior Notes due 2019 | 297,480 | |
| Debt issuance costs | (9,826) | (45) |
| Repurchase of equity grants | (717) | (4,344) |
| Dividends to shareholders | (8) | (9) |
| Exercise of options | 141 | 1,161 |
| Tax benefit of excess non qualified stock option deduction | | 3,393 |
| Other debt | 2,822 | |
| Net cash provided by financing activities | 159,492 | 64,556 |
| Net change in cash and cash equivalents | 66 | (5,628) |
| Cash and cash equivalents at beginning of period | 5,229 | 8,761 |
| Cash and cash equivalents at end of period | $ 5,295 | $ 3,133 |

*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 September 30, 2009 and for the three and nine month periods ended September 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 the date this report on Form 10-Q was filed 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 natural 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*** | **September 30, 2009** | **December 31, 2008** |
|---|---|---|
| Tubular goods and equipment | $ 13,516 | $ 14,884 |
| Crude oil | 21,732 | 7,326 |
| | $ 35,248 | $ 22,210 |

Crude oil represents 581,000 barrels of crude oil at September 30, 2009 and 275,000 barrels of crude oil at December 31, 2008. The Company entered into a series of physical delivery forward sale contracts that provide for the sale of stored crude oil through October 2009. The Company sold 124,100 barrels of crude oil from inventory that was delivered in October. Included in the total crude oil inventory were minimum pipeline line fill requirements of 341,000 barrels and 230,000 barrels at September 30, 2009 and December 31, 2008, respectively, which were not currently available for sale. Inventory, including line fill, is valued at the lower of cost or market using the FIFO inventory method.

*Earnings 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 per share computations for the three and nine months ended September 30, 2009 and 2008:

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| | Three months ended September 30, 2009 | 2008 | Nine months ended September 30, 2009 | 2008 |
|---|---|---|---|---|
| ***In thousands, except per share data*** | | | | |
| Income (numerator): | | | | |
| Net income - basic and diluted | $ 34,929 | $ 105,256 | $ 21,824 | $ 320,534 |
| Weighted average shares (denominator): | | | | |
| Weighted average shares - basic | 168,516 | 168,097 | 168,492 | 168,008 |
| Restricted shares | 782 | 879 | 489 | 813 |
| Employee stock options | 408 | 550 | 418 | 656 |
| Weighted average shares - diluted | 169,706 | 169,526 | 169,399 | 169,477 |
| Income per share: | | | | |
| Basic | $ 0.21 | $ 0.63 | $ 0.13 | $ 1.91 |
| Diluted | $ 0.21 | $ 0.62 | $ 0.13 | $ 1.89 |

*New accounting standards*

In December 2007, the Financial Accounting Standards Board ( FASB ) issued Accounting Standards Codification ( ASC ) 805-10 (formerly SFAS No. 141 (R)), *Business Combinations,* and ASC 810-10 (formerly SFAS No. 160), *Noncontrolling Interests in Consolidated Financial Statements, and amendment of ARB No. 51,* which changes how business acquisitions are accounted for and impacts financial statements both on the acquisition date and in subsequent periods. There are also changes in the accounting and reporting for minority interests, which are re-characterized as noncontrolling interests and classified as a component of equity. Both of these standards are effective for the Company for fiscal years beginning on or after December 15, 2008. ASC 805-10 will be applied prospectively while ASC 810-10 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements will be applied prospectively. The adoption of these standards 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 ASC 820-10 (formerly Financial Staff Position SFAS 157-2), *Effective Date of FASB Statement No. 157,* which provided a one year delay of the effective date of ASC 820-10 (formerly SFAS 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 the provisions of the standard to non-financial assets and liabilities. The standard 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, the standard had no effect on these calculations. Both calculations are based primarily on level three inputs. The adoption of the standard on January 1, 2009 did not have a material impact on the Company s financial position or results of operations.

In March 2008, the FASB issued ASC 815-10 (formerly SFAS No. 161), *Disclosures about Derivative Instruments and Hedging Activities,* which amends and expands disclosure requirements 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 the standard beginning January 1, 2009 and it did not have an impact on the Company s financial position or results of operations.

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

ASC 820-10 (formerly FASB Staff Position ( FSP ) No. 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,* provides guidelines for making fair value measurements more consistent. It also includes guidance on identifying circumstances that indicate a transaction is not orderly. The Company adopted this FSP for the period ended June 30, 2009 and the adoption did not have an impact on its financial position or results of operations.

ASC 825-10 (formerly FSP No. FAS 107-1 and APB 28-1), *Interim Disclosures about Fair Value of Financial Instruments*, 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 for the period ended June 30, 2009 and the adoption did not have an impact on its financial position or results of operations.

In May 2009, the FASB issued ASC 855-10 (formerly SFAS No. 165), *Subsequent Events* which 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 previously existed. 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 the standard for the period ending June 30, 2009 and the adoption did not have an impact on its financial position or results of operations.

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In June 2009, the FASB issued ASC 105-10 (formerly SFAS No. 168), *Accounting Standards Codification ™ and the Hierarchy of Generally Accepted Accounting Principles.* The FASB Accounting Standards Codification ™ ( Codification ) has 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. All existing accounting standard documents are superseded by the Codification. All other non-grandfathered non-SEC accounting literature not included in the Codification will become non-authoritative. The Codification is effective for financial statements issued for interim and annual periods ending after September 15, 2009 and all references made to GAAP in the condensed consolidated financial statements include the new Codification numbering system along with the original references. The Codification does not change or alter existing GAAP and, therefore, did not have an impact on our financial position, results of operations or cash flows.

***Note 3. Cash Flow Information***

Net cash provided by operating activities reflects cash interest payments of $13.7 million for the nine months ended September 30, 2009 and $8.2 million for the nine months ended September 30, 2008. During the first nine months of 2009, the Company received cash payments of $22.0 million for refunds of income taxes paid. Non-cash investing and financing activities include asset retirement obligations of $0.6 million and $3.5 million for the nine months ended September 30, 2009 and 2008, respectively.

***Note 4. Derivative Contracts***

The Company is required to recognize 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. As a result, the Company marked its derivative instruments to fair value and recognized the realized and unrealized change in fair value on derivative instruments in the statements of income.

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 September 30, 2009** | **2008** | **Nine months ended September 30, 2009** | **2008** |
|---|---|---|---|---|
| Realized loss on derivatives: | | | | |
| Crude oil fixed price swaps | $ | $ | $ | $ (34,669) |
| Unrealized gain (loss) on derivatives | | | | |
| Crude oil fixed price swaps | | | | 26,703 |
| Natural gas fixed price swaps | (1,134) | | 701 | |
| Natural gas basis swaps | (971) | | (1,916) | |
| Derivative fair value loss | $ (2,105) | $ | $ (1,215) | $ (7,966) |

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The table below provides data about the carrying values of derivatives that do not qualify for hedge accounting.

| | September 30, 2009 | | | December 31, 2008 | | |
|---|---|---|---|---|---|---|
| *In thousands* | Assets Carrying Value | (Liabilities) Carrying Value | Net Carrying Value | Assets Carrying Value | (Liabilities) Carrying Value | Net Carrying Value |
| Derivative that do not qualify for hedge accounting: | | | | | | |
| Fixed price swaps | $ 701 | $ | $ 701 | $ | $ | $ |
| Basis swaps | | (1,916) | (1,916) | | | |
| | $ 701 | $ (1,916) | $ (1,215) | $ | $ | $ |

***Note 5. Fair Value Measures***

The Company is required to calculate fair value based on a 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*

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 our 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 pricing levels that were accounted for at fair value on a recurring basis as of September 30, 2009:

| | Fair value measurements using | | | |
|---|---|---|---|---|
| **Description** | Level 1 | Level 2 | Level 3 | Total |
| *In thousands* | | | | |
| Derivatives: | | | | |
| Fixed price swaps | $ | $ 701 | $ | $ 701 |
| Basis swaps | $ | $ (1,916) | $ | $ (1,916) |

The following table sets forth the fair value of financial instruments that are not recorded at fair value in our Unaudited Condensed Consolidated Financial Statements.

| | September 30, 2009 | | December 31, 2008 | |
|---|---|---|---|---|
| *In thousands* | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Revolving credit facility | $ 246,000 | $ 246,000 | $ 376,400 | $ 376,400 |
| 8.25% Senior Notes due 2019 | 297,483 | 308,625 | | |

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*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* 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 natural gas properties were reviewed for impairment at September 30, 2009 and the Company determined that the carrying amount was recoverable from future cash flows and, therefore, had no impairment on developed oil and natural gas properties at September 30, 2009. A similar calculation at June 30, 2009, determined that the carrying amount of certain fields were not recoverable from future cash flows and, therefore, were impaired. 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 were $36.1 million for the nine months ended September 30, 2009.

*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 nine months ended September 30, 2009 was $976,000. The fair value of ARO is calculated using significant unobservable inputs (Level 3).

***Note 6. Long-term Debt***

Long-term debt consists of the following:

| ***In thousands*** | **September 30, 2009** | **December 31, 2008** |
|---|---|---|
| Revolving credit facility: | | |
| Prime rate based loans | $ 56,000 | $ |
| LIBOR based loans | 190,000 | 376,400 |
| Total revolving credit facility | 246,000 | 376,400 |
| 8.25% Senior Notes due 2019 | 297,483 | |
| Information Technology Financing Arrangement | 2,822 | |
| Total debt | $ 546,305 | $ 376,400 |

*Revolving credit facility* The Company had $246.0 million and $376.4 million in long-term debt outstanding at September 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 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 (prime). 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 in June 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 2.84% at September 30, 2009. Amounts outstanding under the revolving credit facility at September 30, 2009 are stated at cost, which approximates fair value.

The Company had $504.0 million of unused commitments under the revolving credit facility at September 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 September 30, 2009.

*8.25% Senior Notes due 2019* On September 23, 2009, the Company issued $300 million of 8.25% Senior Notes due 2019 ( Notes ). The Notes, which carry a coupon rate of 8.25%, were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. The Company received net proceeds of approximately $289.7 million, after deducting the underwriters discounts of approximately $6.8 million and offering expenses of approximately $1.0 million. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

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The Notes will mature on October 1, 2019, and interest is payable on the Notes on each April 1 and October 1, commencing April 1, 2010. The Company has the option to redeem all or a portion of the Notes at any time on or after October 1, 2014 at the redemption price specified in the Indenture dated September 23, 2009 (the Indenture ) plus accrued and unpaid interest. The Company may also redeem the Notes, in whole or in part, at a make-whole redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to October 1, 2014. In addition, the Company may redeem up to 35% of the Notes prior to October 1, 2012 under certain circumstances with the net cash proceeds from certain equity offerings. The Indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make investments, create liens on our assets, engage in transactions with our affiliates, transfer or sell assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants as of September 30, 2009. The Notes are not subject to any sinking fund requirements. Our sole subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees this debt.

*Information Technology Financing Arrangement* On August 21, 2009, the Company entered into a Project Financing Agreement with IBM Credit LLC pursuant to which IBM Credit may advance up to $10.0 million for information technology services and software products to be provided to us by International IBM. The financing agreement matures on September 30, 2013, is unsecured and the interest rate under the agreement is 4.73%.

***Note 7. Commitments and Contingencies***

*Drilling Commitments.* As of September 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 September 30, 2009 are $16.8 million.

*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 nine months ended September 30, 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 September 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 September 30, 2009 and December 31, 2008, the Company has provided a reserve of $2.8 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 $8.6 million for the nine months ended September 30, 2009 and $6.5 million for the nine months ended September 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 September 30, 2009, options covering 1,916,973 shares had been exercised.

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The Company s stock option activity under the 2000 Plan for the nine months ended September 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 | (53,510) | 2.65 | (53,510) | 2.65 |
| Outstanding September 30, 2009 | 396,690 | 1.09 | 396,690 | 1.09 |

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 nine months ended September 30, 2009 was approximately $1.8 million. At September 30, 2009, all options were exercisable and had a weighted average remaining life of 1.5 years with an aggregate intrinsic value of $15.1 million.

*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 September 30, 2009, the Company had 3,285,697 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 nine months ended September 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 | 348,123 | 34.18 |
| Vested | (69,358) | 26.57 |
| Forfeited | (24,004) | 21.70 |
| Outstanding September 30, 2009 | 1,365,653 | 26.54 |

The fair value of the restricted shares that vested during the nine months ended September 30, 2009 at their vesting date was $1.7 million. As of September 30, 2009, there was $19.8 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.4 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. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2008 and included in our Quarterly Reports on Form 10-Q for the periods ended March 31, 2009 and June 30, 2009.

These forward-looking statements are based on management s current belief, based on currently available information, as to the outcome and timing of future events. Without limiting the generality of the foregoing, certain statements incorporated by reference or included in this report constitute forward-looking statements.

Forward-looking statements may include statements about our:

- 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.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, and sale of oil and natural gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating oil and natural gas reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under Risk Factors in this report, our Annual Report on Form 10-K for the year ended December 31, 2008, our Quarterly Reports on Form 10-Q for the periods ended March 31, 2009 and June 30, 2009, registrations statements filed from time to time with the SEC, and other announcements we make from time to time.

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Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this report.

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**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 15 months and have had a material impact on our operating results as we discuss in detail below.

For the first nine months of 2009, our oil and natural gas production increased to 10,151 MBoe (37,182 Boe per day), up 17% from the first nine 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 nine months of 2009 decreased by 50% to $407.4 million due to a 56% decrease in commodity prices compared to the same period in 2008. Our realized price per Boe decreased $51.72 to $40.92 for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008. While we experienced decreases in production expense and production tax and other expenses of a combined total of $23.7 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 $4.11 per Boe, or 29%, as a result of a 1,220 MBoe increase in sales volumes. For the nine months ended September 30, 2009, oil sales volumes were 196 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 42 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 nine months ended September 30, 2009, was $216.0 million, a decrease of $373.9 million from $589.9 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 nine months ended September 30, 2009, we invested $302.7 million (excluding payments to reduce accruals of $76.9 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, 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. In November 2009 we increased our 2009 capital expenditures budget to $415.0 million. Cash flow from operations as shown on our statements of cash flows was negatively impacted by payments made to reduce prior year accruals and was less than our capital expenditures for the nine months ended September 30, 2009 and will be less than our capital expenditures for 2009. However, we still expect to manage our capital expenditures for the year to be inline with cash generated from current year operating activities.

*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.

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

| | Three months ended September 30, 2009 | Three months ended September 30, 2008 | Nine months ended September 30, 2009 | Nine months ended September 30, 2008 |
|---|---|---|---|---|
| Average daily production: | | | | |
| Oil (Bbl) | 27,552 | 24,937 | 27,265 | 24,368 |
| Natural gas (Mcf) | 58,995 | 50,156 | 59,503 | 44,139 |
| Oil equivalents (Boe) | 37,384 | 33,297 | 37,182 | 31,725 |
| Average prices: (1) | | | | |
| Oil ($/Bbl) | $ 58.78 | $ 108.37 | $ 49.81 | $ 105.78 |
| Natural gas ($/Mcf) | 2.98 | 7.97 | 2.86 | 8.14 |
| Oil equivalents ($/Boe) | 48.19 | 93.21 | 40.92 | 92.64 |
| Production expense ($/Boe) (1) | 6.50 | 8.22 | 6.95 | 8.62 |
| General and administrative expense ($/Boe) (1) | 2.88 | 3.26 | 2.98 | 3.18 |
| EBITDAX (in thousands) (2) | 128,655 | 238,289 | 292,578 | 665,027 |
| Net income (in thousands) | 34,929 | 105,256 | 21,824 | 320,534 |
| Diluted net income per share | 0.21 | 0.62 | 0.13 | 1.89 |

(1) At various times, we have stored oil due to pipeline line fill requirements or because of low prices or we have sold crude oil from inventory. These actions result in differences between our produced and sold crude oil volumes as noted. Oil sales volumes were 55 MBbls more than oil production for the three months ended September 30, 2009 and 7 MBbls more than oil production for the three months ended September 30, 2008. For the nine months ended September 30, 2009 oil sales volumes were 196 MBbls less than oil production and 42 MBbls more than oil production for the nine months ended September 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 September 30, 2009 compared to the three months ended September 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 September 30, 2009 | Three months ended September 30, 2008 |
|---|---|---|
| Oil and natural gas sales | $ 168,372 | $ 286,194 |
| Derivatives losses | (2,105) | |
| Total revenues | 170,204 | 293,609 |
| Operating costs and expenses | 110,918 | 122,450 |
| Other expense | 4,569 | 2,321 |
| Net income, before income taxes | 54,717 | 168,838 |
| Provision for income taxes | 19,788 | 63,582 |
| Net income | $ 34,929 | $ 105,256 |
| Production Volumes: | | |
| Oil (MBbl) | 2,534 | 2,294 |
| Natural gas (MMcf) | 5,427 | 4,614 |
| Oil equivalents (MBoe) | 3,440 | 3,063 |

| | | |
|---|---|---|
| Sales Volumes: | | |
| Oil (MBbl) | 2,589 | 2,301 |
| Natural gas (MMcf) | 5,427 | 4,614 |
| Oil equivalents (MBoe) | 3,494 | 3,070 |
| Average Prices: [1] | | |
| Oil ($/Bbl) | $ 58.78 | $ 108.37 |
| Natural gas ($/Mcf) | $ 2.98 | $ 7.97 |
| Oil equivalents ($/Boe) | $ 48.19 | $ 93.21 |

(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 September 30, | | | | | |
|---|---|---|---|---|---|---|
| | 2009 | | 2008 | | Volume | Percent |
| | Volume | Percent | Volume | Percent | Increase | Increase |
| Oil (MBbl) | 2,534 | 74% | 2,294 | 75% | 240 | 10% |
| Natural Gas (MMcf) | 5,427 | 26% | 4,614 | 25% | 813 | 18% |
| Total (MBoe) | 3,440 | 100% | 3,063 | 100% | 377 | 12% |

| | Three months ended September 30, | | | | Volume | Percent |
|---|---|---|---|---|---|---|
| | 2009 | | 2008 | | increase | increase |
| | MBoe | Percent | MBoe | Percent | (decrease) | (decrease) |
| Rocky Mountain | 2,608 | 76% | 2,326 | 76% | 282 | 12% |
| Mid-Continent | 791 | 23% | 692 | 23% | 99 | 14% |
| Gulf Coast | 41 | 1% | 45 | 1% | (4) | (9)% |
| Total (MBoe) | 3,440 | 100% | 3,063 | 100% | 377 | 12% |

Oil production volumes increased 10% during the three months ended September 30, 2009 compared to the three months ended September 30, 2008. Production increases in the Bakken field and the Red River units contributed incremental volumes in 2009 of 274 MBbls in excess of production for the third 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 19 MBbl decrease in the Rockies Other area. Natural gas volumes increased 813 MMcf, or 18%, during the three months ended September 30, 2009 compared to the same period in 2008. The Mid-Continent region increased 676 MMcf due to the results of our exploration efforts in the Arkoma Woodford play. The Rocky Mountain region natural gas production was up 160 MMcf for the three months ended September 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 September 30, 2009 were $168.4 million, a 41% decrease from sales of $286.2 million for the same period in 2008. Our sales volumes increased 423 MBoe or 14% over the same period in 2008 due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe decreased $45.01 to $48.19 for the three months ended September 30, 2009 from $93.21 for the three months ended September 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 September 30, 2009 was $9.39 compared to $9.68 for the three months ended September 30, 2008, $6.02 for the second 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.* The Company is required to recognize 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. As a result, we marked our derivative instruments to fair value and recognized the realized and unrealized change in fair value on derivative instruments in the statements of income under the caption Loss on mark-to-market derivative instruments.

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 a portion of our natural gas production. We reported non-cash unrealized mark-to-market losses from our gas derivatives of $2.1 million for the three months ended September 30, 2009. Currently our crude oil production remains unhedged.

*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 units were lower for the three months ended September 30, 2009 than the comparable 2008 period. The price decreased $56.01 per barrel

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which decreased reclaimed oil income by $2.7 million contributing to an overall decrease in oil and gas service operations revenue of $3.5 million for the three months ended September 30, 2009. Associated oil and natural gas service operations expenses decreased $2.8 million to $2.3 million during the three months ended September 30, 2009 from $5.1 million during the three months ended September 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 $0.5 million for the three months ended September 30, 2009 compared to $0.8 million for the three months ended September 30, 2008.

***Operating Costs and Expenses***

*Production Expense and Production Tax and Other Expenses*. Production expense decreased $2.5 million, or 10%, during the three months ended September 30, 2009 to $22.7 million from $25.2 million during the three months ended September 30, 2008. Production expense per Boe decreased to $6.50 for the three months ended September 30, 2009 from $8.22 per Boe for the three months ended September 30, 2008 due to a decrease in workover expenses coupled with an increase in sales volumes.

Production tax and other expenses decreased $5.6 million, or 31%, during the three months ended September 30, 2009 compared to the three months ended September 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 income includes other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma area of $1.5 million and $1.1 million for the three months ended September 30, 2009 and 2008, respectively. Production tax, excluding other charges, as a percentage of oil and natural gas sales was 6.7% for the three months ended September 30, 2009 compared to 5.6% for the three months ended September 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:

| | Three months ended September 30, | | Percent |
|---|---|---|---|
| ***$/Boe*** | **2009** | **2008** | **Decrease** |
| Production expense | $ 6.50 | $ 8.22 | (21)% |
| Production tax and other expenses | 3.54 | 5.84 | (39)% |
| Production expense, production tax and other expenses | $ 10.04 | $ 14.06 | (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 $14.2 million in the three months ended September 30, 2009 to $1.1 million due primarily to a decrease in dry hole expense of $7.7 million and seismic expense of $6.3 million.

*Depreciation, Depletion, Amortization and Accretion ( DD&A ).* Total DD&A increased $11.9 million in the third quarter of 2009 compared to the third quarter of 2008, primarily due to an increase in 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 reserve 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.

| | Three months ended September 30, | |
|---|---|---|
| ***$/Boe*** | **2009** | **2008** |
| Oil and natural gas | $ 14.22 | $ 12.30 |
| Other equipment | 0.22 | 0.27 |
| Asset retirement obligation accretion | 0.16 | 0.17 |
| Depreciation, depletion, amortization and accretion | $ 14.60 | $ 12.74 |

*Property Impairments.* Property impairments, non-producing and developed, increased in the three months ended September 30, 2009 by $1.9 million to $11.8 million compared to $9.9 million during the three months ended September 30, 2008. Impairment of non-producing properties increased $8.9 million during the three months ended September 30, 2009 to $11.8 million compared to $2.9 million for the three months ended September 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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We did not record any impairment provisions for developed oil and gas properties for the three months ended September 30, 2009 compared to approximately $7.0 million for the three months ended September 30, 2008. 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. For the three months ended September 30, 2009, future cash flows were determined to be in excess of cost basis and no impairment was necessary.

*General and Administrative Expense.* General and administrative expense did not materially change during the three months ended September 30, 2009 compared to the same period in 2008. General and administrative expense includes non-cash charges for stock-based compensation of $3.2 million and $2.6 million for the three months ended September 30, 2009 and 2008, respectively. General and administrative expense excluding equity compensation decreased $0.6 million for the three months ended September 30, 2009 compared to the same period in 2008. On a volumetric basis, general and administrative expense decreased $0.38 to $2.88 per Boe for the three months ended September 30, 2009 compared to $3.26 per Boe for the three months ended September 30, 2008.

*Interest Expense.* Interest expense increased 90%, or $2.3 million, for the three months ended September 30, 2009 compared to the three months ended September 30, 2008, due to higher debt balances. Our average revolving credit facility balance increased to $558.8 million for the three months ended September 30, 2009 compared to $233.7 million for the three months ended September 30, 2008, but the weighted average interest rate on our revolving credit facility was lower at 2.59% for the three months ended September 30, 2009 compared to 3.94% 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 that could not be funded from cash flows from operations due to the significant decrease in commodity prices. At October 31, 2009 our outstanding revolving credit facility balance was $240.0 million with a weighted average interest rate of 2.70%. On September 23, 2009, we issued $300 million of 8.25% Senior Notes due 2019 ( Notes ). The Notes, which carry a coupon rate of 8.25%, were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. The Notes had minimal effect on interest expense for the quarter ended September 30, 2009 but will increase interest expense and our average interest rate in future periods.

*Income Taxes.* We recorded income tax expense for the three months ended September 30, 2009 of $19.8 million compared to $63.6 million for the three months ended September 30, 2008. We provide taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

**Nine months ended September 30, 2009 compared to the nine months ended September 30, 2008**

**Results of Operations**

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

| | Nine months ended September 30, | |
|---|---|---|
| ***In thousands, except volume price data*** | **2009** | **2008** |
| Oil and natural gas sales | $ 407,379 | $ 809,238 |
| Derivatives losses | (1,215) | (7,966) |
| Total revenues | 418,573 | 824,694 |
| Operating costs and expenses | 371,538 | 306,613 |
| Other expense | 13,431 | 8,050 |
| Net income, before income taxes | 33,604 | 510,031 |
| Provision for income taxes | 11,780 | 189,497 |
| Net income | $ 21,824 | $ 320,534 |
| Production Volumes: | | |
| Oil (MBbl) | 7,443 | 6,677 |
| Natural gas (MMcf) | 16,244 | 12,094 |
| Oil equivalents (MBoe) | 10,151 | 8,693 |
| Sales Volumes: | | |
| Oil (MBbl) | 7,247 | 6,719 |
| Natural gas (MMcf) | 16,244 | 12,094 |

| | | | | |
|---|---|---|---|---|
| Oil equivalents (MBoe) | | 9,955 | | 8,735 |
| Average Prices: [1] | | | | |
| Oil ($/Bbl) | $ | 49.81 | $ | 105.78 |
| Natural gas ($/Mcf) | $ | 2.86 | $ | 8.14 |
| Oil equivalents ($/Boe) | $ | 40.92 | $ | 92.64 |

(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.

| | Nine months ended September 30, | | | | | |
|---|---|---|---|---|---|---|
| | 2009 | | 2008 | | Volume | Percent |
| | Volume | Percent | Volume | Percent | increase | increase |
| Oil (MBbl) | 7,443 | 73% | 6,677 | 77% | 766 | 11% |
| Natural Gas (MMcf) | 16,244 | 27% | 12,094 | 23% | 4,150 | 34% |
| Total (MBoe) | 10,151 | 100% | 8,693 | 100% | 1,458 | 17% |

| | Nine months ended September 30, | | | | Volume | Percent |
|---|---|---|---|---|---|---|
| | 2009 | | 2008 | | increase | increase |
| | MBoe | Percent | MBoe | Percent | (decrease) | (decrease) |
| Rocky Mountain | 7,634 | 75% | 6,728 | 77% | 906 | 13% |
| Mid-Continent | 2,371 | 23% | 1,809 | 21% | 562 | 31% |
| Gulf Coast | 146 | 2% | 156 | 2% | (10) | (6)% |
| Total (MBoe) | 10,151 | 100% | 8,693 | 100% | 1,458 | 17% |

Oil production volumes increased 11% during the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008. Production increases in the Bakken field area contributed incremental volumes in excess of production for the same period in 2008 of 799 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 58 MBbl decrease in the Rockies Other area. Natural gas volumes increased 4.2 Bcf, or 34%, during the nine months ended September 30, 2009 compared to the same period in 2008. The majority of the increase, 3.5 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 657 MMcf for the nine months ended September 30, 2009 compared to the same period in 2008 mainly 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 nine months ended September 30, 2009 were $407.4 million, a 50% decrease from sales of $809.2 million for the same period in 2008. Our sales volumes increased 1,220 MBoe or 14% over the same period in 2008 due to the continuing success of our enhanced oil recovery and drilling programs. Our realized price per Boe decreased $51.72 to $40.92 for the nine months ended September 30, 2009 from $92.64 for the nine months ended September 30, 2008. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the nine months ended September 30, 2009 was $7.91 compared to $7.64 for the nine months ended September 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.* The Company is required to recognize 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. As a result, we marked our derivative instruments to fair value and recognized the realized and unrealized change in fair value on derivative instruments in the statements of income under the caption 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 nine months ended September 30, 2008 we 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 losses from our gas derivatives of $1.2 million for the nine months ended September 30, 2009.

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*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 nine months ended September 30, 2009 than the comparable 2008 period. The price decreased $64.55 per barrel which decreased reclaimed oil income by $10.4 million contributing to an overall decrease in oil and gas service operations revenue of $11.0 million for the nine months ended September 30, 2009. Associated oil and natural gas service operations expenses decreased $8.4 million to $7.4 million during the nine months ended September 30, 2009 from $15.8 million during the same period in 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 $1.6 million and $2.2 million for the nine months ended September 30, 2009 and 2008, respectively.

***Operating Costs and Expenses***

*Production Expense, Production Tax and Other Expenses*. Production expense decreased $6.1 million, or 8%, during the nine months ended September 30, 2009 to $69.2 million from $75.3 million during the nine months ended September 30, 2008. During the nine months ended September 30, 2009, we participated in the completion of 175 gross (58.1 net) wells. Production expense per Boe decreased to $6.95 for the nine months ended September 30, 2009 from $8.62 per Boe for the nine months ended September 30, 2008 due to decreases in workover expenses and energy costs coupled with an increase in sales volumes.

Production tax and other expenses decreased $17.6 million, or 36%, during the nine months ended September 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 income includes other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma area of $5.4 million and $2.1 million for the nine months ended September 30, 2009 and 2008, respectively. Production tax, excluding other charges, as a percentage of oil and natural gas sales was 6.4% for the nine months ended September 30, 2009 compared to 5.7% for the nine months ended September 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:

| | Nine months ended September 30, | | Percent |
|---|---|---|---|
| ***$/Boe*** | **2009** | **2008** | **Decrease** |
| Production expense | $ 6.95 | $ 8.62 | (19)% |
| Production tax and other expenses | 3.10 | 5.54 | (44)% |
| Production expense, production tax and other expenses | $ 10.05 | $ 14.16 | (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 $16.6 million in the nine months ended September 30, 2009 to $9.7 million due primarily to a decrease in seismic expense of $12.8 million to $1.5 million and a decrease in dry hole expense of $4.4 million to $5.0 million. The majority of the dry hole costs were in the Mid-Continent region for the nine months ended September 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 $59.0 million during the nine months of 2009 compared to the same time period in 2008, primarily 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 reserve 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.

| | Nine months ended September 30, | |
|---|---|---|
| ***$/Boe*** | **2009** | **2008** |
| Oil and natural gas | $ 15.16 | $ 10.57 |

| | | | | |
|---|---|---|---|---|
| Other equipment | | 0.23 | | 0.22 |
| Asset retirement obligation accretion | | 0.17 | | 0.17 |
| Depreciation, depletion, amortization and accretion | $ | 15.56 | $ | 10.96 |

*Property Impairments.* Property impairments, non-producing and developed, increased in the nine months ended September 30, 2009 by $52.9 million to $70.5 million compared to $17.6 million during the nine months ended September 30, 2008. Impairment of

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non-producing properties increased $25.6 million during the nine months ended September 30, 2009 to $34.4 million compared to $8.8 million for the nine months ended September 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 nine months ended September 30, 2009 compared to approximately $8.8 million for the nine months ended September 30, 2008, an increase of $27.3 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 nine months ended September 30, 2009. The remaining impairments are the result of decreases in reserves and prices.

*General and Administrative Expense.* General and administrative expense increased $1.9 million to $29.7 million during the nine months ended September 30, 2009 from $27.8 million during the comparable period of 2008. General and administrative expense includes non-cash charges for stock-based compensation of $8.6 million and $6.5 million for the nine months ended September 30, 2009 and 2008, respectively. General and administrative expense excluding equity compensation increased $0.5 million for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008. The increase was primarily related to an increase in litigation expense of $0.8 million and a $0.7 million 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 $2.98 per Boe for the nine months ended September 30, 2009 compared to $3.18 per Boe for the nine months ended September 30, 2008 due mainly to increased production volumes.

*Interest Expense.* Interest expense increased 60%, or $5.3 million, for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008, due to higher debt balances. Our average revolving credit facility balance increased to $550.7 million for the nine months ended September 30, 2009 compared to $227.6 million for the nine months ended September 30, 2008, but the weighted average interest rate on our revolving credit facility decreased to 2.90% for the nine months ended September 30, 2009 compared to 4.66% 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 that could not be funded from cash flows from operations due to the significant decrease in commodity prices. At October 31, 2009 our outstanding revolving credit facility balance was $240.0 million with a weighted average interest rate of 2.70%. On September 23, 2009, we issued $300 million of 8.25% Senior Notes due 2019. The Notes, which carry a coupon rate of 8.25%, were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. The Notes had minimal effect on interest expense for the quarter ended September 30, 2009 but will increase interest expense and our average interest rate in future periods.

*Income Taxes.* We recorded an income tax expense for the nine months ended September 30, 2009 of $11.8 million compared to a $189.5 million expense for the nine months ended September 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, financing provided by our revolving credit facility and the issuance of the Notes in September 2009. 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 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 improved 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. We believe that our current syndicate banks 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 began to see 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. On September 23, 2009, we issued $300 million of 8.25% Senior Notes due 2019 and received net proceeds of approximately $289.7 million after deducting the underwriters discounts and other expenses and after giving effect to the discount at which the Notes were issued. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility. As of September 30, 2009, we had $504.0 million available under our revolving credit facility and $24.0 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.

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 additional 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 revolving credit facility 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. Our next borrowing base redetermination is scheduled to occur later in the fourth quarter of 2009.

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 $216.0 million and $589.9 million for the nine months ended September 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 nine months ended September 30, 2009 and 2008 we had cash flows used in investing activities (excluding asset sales) of $378.2 million and $662.3 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 decreases in capital expenditures as a result of lower commodity prices in 2009.

***Cash Flow from Financing Activities***

Net cash provided by financing activities of $159.5 million for the nine months ended September 30, 2009 primarily represents amounts received from the issuance of the Notes less amounts repaid under our revolving credit facility to fund capital expenditures, including the reduction in accounts payable. Net cash provided by financing activities of $64.6 million for the nine months ended September 30, 2008 was mainly the result of amounts borrowed under our revolving credit facility to fund capital expenditures, including acquisitions.

***Revolving Credit Facility***

We had $246.0 million and $376.4 million outstanding under our revolving credit facility at September 30, 2009 and December 31, 2008, respectively. The decrease was largely due the repayment of a portion of the outstanding borrowings under our revolving credit facility with the net proceeds from the issuance of the Notes in September 2009. The revolving credit facility currently has a borrowing base of $850.0 million, which is 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 from $672.5 million, which equals the maximum note amount.

***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.

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, in August 2009 we 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. In November 2009 we increased our 2009 capital expenditures budget to $415.0 million. Under our original $275 million capital expenditures budget for 2009, only one Company-operated rig would have been active from September through December 2009. We have reduced our rig count from 32 operated rigs in October 2008 to 4 operated rigs at September 30, 2009. We have a contract remaining on one of these rigs that expires in August 2011. We currently expect to exit 2009 with 12 operated drilling rigs, with six of those deployed in North Dakota Bakken and one in Montana Bakken.

During the first nine months of 2009, we participated in the completion of 175 gross (58.1 net) wells and invested a total of $302.7 million (excluding payments to reduce accruals of $76.9 million and including seismic) for capital expenditures in 2009.

| | Capital Expenditures | |
|---|---|---|
| *In millions* | **Budgeted for 2009** | **Actual nine months ended September 30, 2009** |
| Exploration and development drilling | $ 294.8 | $ 237.0 |
| Acquisition of producing properties | | 1.2 |
| Capital facilities, workovers and re-completions | 37.0 | 17.8 |
| Land costs | 74.2 | 40.7 |
| Seismic | 2.1 | 1.4 |
| Vehicles, computers and other equipment | 6.9 | 4.6 |
| Total | $ 415.0 | $ 302.7 |

Cash flow from operations as shown on our statements of cash flows was negatively impacted by payments made to reduce prior year accruals and was less than our capital expenditures for the nine months ended September 30, 2009 and will be less than our capital expenditures for the year 2009. However, we still expect to manage our capital expenditures for the year to be inline with cash generated from current year operating activities. 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.

Based on strong cash flow and our positive outlook, in November 2009, our Board of Directors approved a preliminary 2010 capital expenditures budget of $650 million. We expect to have 23 operated drilling rigs deployed by mid-2010. The 2010 capital expenditures budget will primarily focus on increased development in the North Dakota Bakken, the Arkoma and Anadarko Woodford shale natural gas plays in Oklahoma and the Red River Units. Operational capital expenditures (drilling, work-over and related facilities) account for $563 million of the capital expenditures budget. In addition, we plan to invest $73 million for new leases and lease retention, primarily in the Bakken and Woodford plays.

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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 fund our current 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 31, 2008, SEC issued Release No. 33-8995, *Modernization of Oil and Gas Reporting*. Release 33-8995 adopts revisions to the SEC s oil and gas reporting disclosure requirements and is effective for annual reports on Forms 10-K for years ending on or after December 31, 2009. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves to help investors evaluate their investments in oil and gas companies. The amendments are also designed to modernize the oil and gas disclosure requirements to align them with current practices and changes in technology. Revised requirements in Release 33-8995 include, but are not limited to:

- Oil and gas reserves must be reported using the unweighted arithmetic average of the first day of the month prices for each month within the preceding 12 month period, rather than year-end prices;

- Companies will be allowed to report, on an optional basis, probable and possible reserves;

- Companies will be permitted to use new technologies to determine proved reserves, as long as those technologies have been demonstrated empirically to lead to reliable conclusions with respect to reserve volumes;

- Companies will be required to disclose, in narrative form, additional details about their proved undeveloped reserves (PUDs), including the total quantity of PUDs at year end, any material changes to PUDs that occurred during the year, investments and progress made to convert PUDs to developed oil and gas reserves and an explanation of the reasons why material concentrations of PUDs in individual fields or countries have remained undeveloped for five years or more after disclosure as PUDs; and

- Companies will be required to report the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserves estimates.

We are currently evaluating the impact of adopting the Release 33-8995 on our financial statements and disclosures. The SEC is discussing the Release 33-8995 with the FASB staff to align FASB accounting standards with the new SEC rules. We will comply with the disclosure requirements in our annual report on Form 10-K for the year ended December 31, 2009.

In October 2009, the SEC issued Staff Accounting Bulletin No. 113 (SAB No. 113), which revises portions of the interpretive guidance included in the section of the Staff Accounting Bulletin Series titled *Topic 12: Oil and Gas Producing Activities* (Topic 12). The principal changes involve revisions to bring Topic 12 into conformity with the contents of Release 33-8995. We are currently evaluating the impact of adopting the SAB No. 113 on our financial statements and disclosures.

For a description of the accounting standards that we adopted in 2009, please see Note 2. Basis of Presentation and Significant Accounting Policies above.

***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

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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 revolving 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. We were in compliance with this covenant at September 30, 2009. Our revolving 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.

| *In thousands* | Three months ended September 30, 2009 | Three months ended September 30, 2008 | Nine months ended September 30, 2009 | Nine months ended September 30, 2008 |
|---|---|---|---|---|
| Net income | $ 34,929 | $ 105,256 | $ 21,824 | $ 320,534 |
| Unrealized loss on derivative instruments | 2,105 | | 1,215 | |
| Interest expense | 4,763 | 2,506 | 14,073 | 8,782 |
| Provision for income taxes | 19,788 | 63,582 | 11,780 | 189,497 |
| Depreciation, depletion, amortization and accretion | 51,030 | 39,120 | 154,875 | 95,828 |
| Property impairments | 11,791 | 9,947 | 70,491 | 17,620 |
| Exploration expense | 1,077 | 15,285 | 9,726 | 26,278 |
| Non-cash compensation expense | 3,172 | 2,593 | 8,594 | 6,488 |
| EBITDAX | $ 128,655 | $ 238,289 | $ 292,578 | $ 665,027 |

**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 nine months ended September 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 September 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 September 30, 2009, we recorded a liability of $1.2 million for unrealized losses on derivatives.

In July 2007, we entered into fixed-price swap contracts covering 10,000 barrels of oil per day for the period from August 2007 through April 2008 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 nine months ended September 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 ($53.1 million at September 30, 2009) and the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($105.4 million in receivables at September 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 interest. 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 revolving credit facility debt of $240.0 million outstanding under our revolving credit facility at October 31, 2009. The impact of a 1% increase in interest rates on this amount of debt would increase interest expense by approximately $2.4 million per year. Our revolving credit facility debt matures in 2011 and the weighted-average interest rate at October 31, 2009 was 2.70%.

## ITEM 4. Controls and Procedures

**Evaluation of Disclosure Controls and Procedures**

Based on 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 ) were effective as of September 30, 2009. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that the 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 and is recorded, processed, summarized and reported within the time period in the rules and forms of the SEC.

**Changes in Internal Control over Financial Reporting**

During the quarter ended September 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, individually or in the aggregate, 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 and our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2009 and June 30, 2009, other than the addition of the following risk factor.

***The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.***

We occasionally enter into commodity derivative contracts in order to hedge a portion of our crude oil and natural gas production. Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including natural gas and oil, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC s expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The CFTC is considering whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. Separately, two committees of the House of Representatives, the Financial Services and Agriculture Committees, acted on October 15, 2009 and October 21, 2009, respectively, to adopt legislation that would impose comprehensive regulation on the over-the-counter (OTC) derivatives marketplace. This legislation would subject swap dealers and major swap participants to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants, and would provide the CFTC with authority to impose position limits in the OTC derivatives markets. A major swap participant generally would be someone other than a dealer who maintains a substantial position in outstanding swaps other than swaps used for commercial hedging, or whose positions create substantial exposure to its counterparties or the system. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

### 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 September 30, 2009:

| Period | (a) Total number of shares purchased (1) | (b) Average price paid per share (2) | (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 (3) |
|---|---|---|---|---|
| July 1, 2009 to July 31, 2009 | 826 | $ 23.91 | | |
| August 1, 2009 to August 31, 2009 | 9,480 | 24.31 | | |
| September 1, 2009 to September 30, 2009 | | | | |
| Total | 10,306 | $ 24.28 | | |

(1) 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. The 2000 Plan was adopted in October 2000 and was terminated in November 2005. The 2005 Plan was adopted in October 2005 and expires in October 2015. All shares purchased above represent shares surrendered to cover tax liabilities. We paid the associated taxes to the Internal Revenue Service.

(2) The price paid per share was the closing price of our common stock on the date of exercise or the date the restrictions lapsed on such shares, as applicable.

(3) We are unable to determine at this time the total amount of securities or approximate dollar value of those securities that could potentially be surrendered to us pursuant to our policy that enables employees to surrender shares to cover their tax liability associated with the exercise of options or vesting of restrictions on shares under the 2000 Plan and 2005 Plan.

**ITEM 3. Defaults Upon Senior Securities**

Not applicable.

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

Not applicable.

**ITEM 5. Other Information**

Not applicable.

**ITEM 6. Exhibits**

The exhibits required to be filed pursuant to Item 601 of Regulation S-K are set forth in the Index to Exhibits accompanying this report and are incorporated herein by reference.

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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: November 5, 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. |
| 4.3 | Indenture dated as of September 23, 2009 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and Wilmington Trust FSB, as trustee, filed as Exhibit 4.1 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed September 24, 2009 and incorporated herein by reference. |
| 4.4 | Registration Rights Agreement dated as of September 23, 2009 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and the Initial Purchasers named therein, filed as Exhibit 4.2 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed September 24, 2009 and incorporated herein by reference. |
| 10.1 | Purchase Agreement dated as of September 18, 2009 among Continental Resources, Inc., Banner Pipeline Company, L.L.C. and the Initial Purchasers named therein, filed as Exhibit 10.1 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed September 24, 2009 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). |