CONTINENTAL RESOURCES INC
Form 10-Q
August 06, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2010

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 x 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

169,959,944 shares of our $0.01 par value common stock were outstanding on July 31, 2010.

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

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Glossary of Crude 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.

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

Boepd. Barrels of crude oil equivalent per day.

Bopd. Barrels of crude oil per day.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or crude 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 crude oil and natural gas through the injection of liquids or gases into the reservoir. 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.

FIFO. (First in/First out) A cost flow assumption where the first (oldest) costs are assumed to flow out first. This means the latest (recent) costs remain on hand.

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.

Mcfd. Mcf per day.

MBoe. One thousand Boe.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMMBtu. One billion British thermal units.

NYMEX. The New York Mercantile Exchange.

Play. A portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential crude oil and natural gas reserves.

Proved reserves. These quantities of crude oil and natural gas which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

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 crude 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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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 Reform Act of 1995. All statements, other than statements of historical fact, included in this report are forward-looking statements. When used in this report, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements are based on the Company s 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 Item 1A. Risk Factors included in this report and in our Annual Report on Form 10-K for the year ended December 31, 2009.

These forward-looking statements reflect 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, if any, or included in this report constitute forward-looking statements.

Forward-looking statements may include statements about our:

business strategy;

future operations;

reserves;

technology;

financial strategy;

crude oil and natural gas prices;

timing and amount of future production of crude oil and natural gas;

the amount, nature and timing of capital expenditures;

estimated revenues and losses;

drilling of wells;

competition and government regulations;

- marketing of crude oil and natural gas;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- financial position;
- 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 crude 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 crude oil and natural gas reserves and in projecting future rates of production, cash flows and access to capital,

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the timing of development expenditures, and the other risks described under Item 1A. Risk Factors in this report, our Annual Report on Form 10-K for the year ended December 31, 2009, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. 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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PART I. Financial Information

ITEM 1. Financial Statements

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Balance Sheets

	June 30, 2010 (Unaudited)	December 31, 2009
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 15,232	$ 14,222
Receivables:		
Oil and natural gas sales	146,643	119,565
Affiliated parties	11,274	7,823
Joint interest and other, net	148,006	55,970
Derivative assets	47,272	2,218
Inventories	39,218	26,711
Deferred and prepaid taxes	20	4,575
Prepaid expenses and other	5,624	4,944
Total current assets	413,289	236,028
Net property and equipment, based on successful efforts method of accounting	2,442,252	2,068,055
Debt issuance costs, net	20,725	10,844
Noncurrent derivative assets	15,353	
Total assets	$ 2,891,619	$ 2,314,927
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 291,126	$ 91,248
Revenues and royalties payable	79,842	66,789
Payables to affiliated parties	3,344	9,612
Accrued liabilities and other	74,366	49,601
Current portion of asset retirement obligations	2,695	2,460
Total current liabilities	451,373	219,710
Long-term debt	609,844	523,524
Other noncurrent liabilities:		
Deferred income tax liabilities	566,124	489,241
Asset retirement obligations, net of current portion	48,494	47,707
Other noncurrent liabilities	6,311	4,466
Total other noncurrent liabilities	620,929	541,414
Commitments and contingencies (Note 8)		
Shareholders equity:		
Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding		
	1,700	1,700

Common stock, $0.01 par value; 500,000,000 shares authorized, 169,972,694 shares issued and outstanding at June 30, 2010; 169,968,471 shares issued and outstanding at December 31, 2009				
Additional paid-in-capital		435,271		430,283
Retained earnings		772,502		598,296
Total shareholders equity		1,209,473		1,030,279
Total liabilities and shareholders equity	$	2,891,619	$	2,314,927

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

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Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Operations

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	In thousands, except per share data			
Revenues:				
Oil and natural gas sales	$ 211,204	$ 141,028	$ 419,263	$ 226,845
Oil and natural gas sales to affiliates	8,222	5,411	17,287	12,162
Gain on mark-to-market derivative instruments	55,465	890	81,809	890
Oil and natural gas service operations	5,077	4,432	9,877	8,472
Total revenues	279,968	151,761	528,236	248,369
Operating costs and expenses:				
Production expenses	21,259	21,458	40,418	38,732
Production expenses to affiliates	1,089	2,580	4,531	7,732
Production taxes and other expenses	18,231	11,629	34,238	18,451
Exploration expenses	2,269	1,530	4,055	8,649
Oil and natural gas service operations	4,091	2,694	8,047	5,097
Depreciation, depletion, amortization and accretion	58,822	53,148	111,409	103,845
Property impairments	19,514	23,275	34,689	58,700
General and administrative expenses	11,494	9,351	23,343	19,635
Gain on sale of assets	(33,124)	(85)	(33,346)	(221)
Total operating costs and expenses	103,645	125,580	227,384	260,620
Income (loss) from operations	176,323	26,181	300,852	(12,251)
Other income (expense):				
Interest expense	(11,903)	(4,723)	(20,263)	(9,310)
Other	78	301	784	448
	(11,825)	(4,422)	(19,479)	(8,862)
Income (loss) before income taxes	164,498	21,759	281,373	(21,113)
Provision (benefit) for income taxes	62,757	8,251	107,167	(8,008)
Net income (loss)	$ 101,741	$ 13,508	$ 174,206	$ (13,105)
Basic net income (loss) per share	$ 0.60	$ 0.08	$ 1.03	$ (0.08)
Diluted net income (loss) per share	$ 0.60	$ 0.08	$ 1.03	$ (0.08)

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, 2009	169,558,129	$ 1,696	$ 420,054	$ 526,958	$ 948,708
Net income				71,338	71,338
Stock-based compensation			11,408		11,408
Tax benefit on stock-based compensation plan			2,872		2,872
Stock options:					
Exercised	138,010	1	244		245
Repurchased and canceled	(29,924)		(1,223)		(1,223)
Restricted stock:					
Issued	411,217	4			4
Repurchased and canceled	(83,457)	(1)	(3,072)		(3,073)
Forfeited	(25,504)				
Balance, December 31, 2009	169,968,471	$ 1,700	$ 430,283	$ 598,296	$ 1,030,279
Net income (unaudited)				174,206	174,206
Stock-based compensation (unaudited)			5,970		5,970
Stock options:					
Exercised (unaudited)	4,500		3		3
Restricted stock:					
Issued (unaudited)	46,343				
Repurchased and canceled (unaudited)	(20,911)		(985)		(985)
Forfeited (unaudited)	(25,709)				
Balance, June 30, 2010 (unaudited)	169,972,694	$ 1,700	$ 435,271	$ 772,502	$ 1,209,473

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 Cash Flows

	Six months ended June 30, 2010	Six months ended June 30, 2009
	In thousands	
Cash flows from operating activities:		
Net income (loss)	$ 174,206	$ (13,105)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	111,417	107,948
Property impairments	34,689	58,700
Change in fair value of derivatives	(64,714)	(890)
Stock-based compensation	5,970	5,422
Provision (benefit) for deferred income taxes	95,500	(8,008)
Dry hole costs	409	4,992
Gain on sale of assets	(33,346)	(221)
Other, net	2,746	1,052
Changes in assets and liabilities:		
Accounts receivable	(104,885)	52,033
Inventories	(12,507)	(17,948)
Prepaid expenses and other	2,387	13,523
Accounts payable trade	153,063	(96,873)
Revenues and royalties payable	13,053	(19,995)
Accrued liabilities and other	11,065	(5,577)
Other noncurrent liabilities	1,172	1,440
Net cash provided by operating activities	390,225	82,493
Cash flows from investing activities:		
Exploration and development	(469,484)	(296,099)
Purchase of oil and natural gas properties	(151)	(437)
Purchase of other property and equipment	(14,261)	(628)
Proceeds from sale of assets	21,332	1,391
Net cash used in investing activities	(462,564)	(295,773)
Cash flows from financing activities:		
Revolving credit facility borrowings	169,000	334,100
Repayment of revolving credit facility	(281,000)	(118,500)
Proceeds from issuance of 7 ^{3}/8% Senior Notes Due 2020	194,210	
Debt issuance costs	(7,876)	(2,118)
Repurchase of equity grants	(985)	(358)
Dividends to shareholders	(3)	(7)
Exercise of options	3	5
Net cash provided by financing activities	73,349	213,122
Net change in cash and cash equivalents	1,010	(158)
Cash and cash equivalents at beginning of period	14,222	5,229
Cash and cash equivalents at end of period	$ 15,232	$ 5,071

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 crude oil and natural gas exploration, development and production. Continental s operations are primarily in the North, South, and East regions of the United States.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

Continental has one wholly owned subsidiary, Banner Pipeline Company, L. L. C., which has no assets or operations. The consolidated financial statements include the accounts of Continental and its wholly owned subsidiary after all significant inter-company accounts and transactions have been eliminated.

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, 2009 (2009 Form 10-K), which includes a summary of the Company s significant accounting policies and other disclosures.

The financial statements as of June 30, 2010 and for the three and six month periods ended June 30, 2010 and 2009 are unaudited. The Condensed Consolidated Balance Sheet as of December 31, 2009 was derived from the audited balance sheet filed in the 2009 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 crude oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment on producing crude 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.

Inventories

Inventories are stated at the lower of cost or market. Inventories consist of the following:

In thousands	**June 30, 2010**	**December 31, 2009**
Tubular goods and equipment	$ 18,163	$ 12,044
Crude oil	21,055	14,667
	$ 39,218	$ 26,711

As of June 30, 2010, total crude oil inventory of 473,500 barrels valued at $21.1 million consisted of approximately 284,000 barrels of line fill requirements and 189,500 barrels of temporarily stored crude oil. As of December 31, 2009, total crude oil inventory of 398,000 barrels valued at $14.7 million consisted of approximately 253,000 barrels of line fill requirements and 145,000 barrels of temporarily stored crude oil.

Inventories, including line fill, are valued at the lower of cost or market using the FIFO inventory method.

Earnings (loss) per common share

Basic earnings per common share is computed by dividing net income (loss) 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 awards and options were exercised. The following is

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the calculation of basic and diluted weighted average shares outstanding and income (loss) per share computations for the three and six months ended June 30, 2010 and 2009:

In thousands, except per share data	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Income (loss) (numerator):				
Net income (loss) - basic and diluted	$ 101,741	$ 13,508	$ 174,206	$ (13,105)
Weighted average shares (denominator):				
Weighted average shares - basic	168,887	168,492	168,872	168,479
Restricted shares	744	584	704	
Employee stock options	301	422	302	
Weighted average shares - diluted	169,932	169,498	169,878	168,479
Income (loss) per share:				
Basic	$ 0.60	$ 0.08	$ 1.03	$ (0.08)
Diluted	$ 0.60	$ 0.08	$ 1.03	$ (0.08)

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

Reclassifications

Certain prior year amounts have been reclassified on the condensed consolidated financial statements to conform to the 2010 presentation. On the condensed consolidated balance sheet as of December 31, 2009, the line item Derivative assets was included in Receivables-Joint interest and other, net and has been shown separately in this report to conform to the 2010 presentation.

Note 3. Related Party Transactions

During the second quarter of 2010, the Company determined that a related party relationship, as defined by SEC rules and U.S. GAAP, did not exist with a third party entity that had been historically accounted for as a related party in the consolidated financial statements. Transactions with this entity are not reflected as affiliate transactions in the unaudited condensed consolidated financial statements as of and for the three months ended June 30, 2010. The balance sheet at December 31, 2009 included $0.1 million from this party in Receivables Affiliated parties and $6.4 million in Payables to affiliated parties . Production expenses to affiliates included $1.8 million in expenses from this party for the six months ended June 30, 2010 and $1.9 million and $4.6 million in expenses from this party for the three and six months ended June 30, 2009, respectively.

Note 4. Supplemental Cash Flow Information

Net cash provided by operating activities reflects cash interest payments of $15.7 million for the six months ended June 30, 2010 and $9.8 million for the six months ended June 30, 2009. During the six months ended June 30, 2010, the Company made cash payments of $5.8 million and received $1.3 million for refunds of income taxes paid. During the six months ended June 30, 2009, the Company received cash payments of $1.9 million for refunds of income taxes paid. Non-cash investing activities include asset retirement obligations of $0.7 million and $0.6 million for the six months ended June 30, 2010 and 2009, respectively.

Note 5. 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 elects not to designate its derivatives as cash flow hedges and as a result marks its derivative instruments to fair value and recognizes the realized and unrealized changes in fair value on derivative instruments in the statements of operations under the caption Gain on mark-to-market derivative instruments.

The Company has utilized swap and collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of future crude oil and natural gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

During the six months ended June 30, 2010, the Company entered into several new swap and collar derivative contracts covering a portion of its crude oil and natural gas production for 2010 and 2011. The new contracts were entered into in the normal course of business and the Company expects to enter into additional similar contracts during the year. None of the new contracts have been designated for hedge accounting.

With respect to a fixed price swap contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make payment to the counterparty if the settlement price for any settlement period is greater than the swap price. For a basis swap contract, which guarantees a price differential between the NYMEX posted prices and the Company s physical pricing points, the Company receives a payment from the counterparty if the settled price differential is greater than the stated terms of the contract and the Company pays the counterparty if the settled price differential is less than the stated terms of the contract. For a collar contract, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price, the Company is required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling price, and neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor price and equal to or less than the ceiling price.

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All of the Company s derivative contracts are carried at their fair value on the consolidated balance sheets under the captions Derivative assets , Noncurrent derivative assets and Accrued liabilities and other. Derivative assets and liabilities with the same counterparty and subject to contractual terms which provide for net settlement are reported on a net basis on the consolidated balance sheets. Substantially all of the crude oil and natural gas derivative contracts are settled based upon reported prices on the NYMEX. The estimated fair value of these contracts is based upon various factors, including closing exchange prices on the NYMEX, over-the-counter quotations, and, in the case of collars, volatility and the time value of options. The calculation of the fair value of collars requires the use of an option-pricing model. See *Note 6. Fair Value Measurements*.

At June 30, 2010, the Company had outstanding contracts with respect to future production as set forth in the tables below.

Crude Oil

			Collars			
		Swaps	Floors		Ceilings	
Period and Type of Contract	**Volume in MBbls**	**Weighted Average**	**Range**	**Weighted Average**	**Range**	**Weighted Average**
July 2010 - December 2010						
Swaps	1,104	$ 85.14				
Collars	2,760		$ 75-$78	$ 76.00	$ 88.75-$96.75	$ 93.43
January 2011 - March 2011						
Swaps	225	84.55				
Collars	1,215		$ 75-$80	77.78	$ 88.65-$97.25	93.10
April 2011 - December 2011						
Collars	3,713		$ 75-$80	78.70	$ 89.00-$97.25	92.19

Natural Gas

Period and Type of Contract	**MMMBtus**	**Swaps Weighted Average**
July 2010 - December 2010		
Swaps	7,556	$ 6.09
January 2011 - December 2011		
Swaps	11,863	6.36

Natural Gas Basis Centerpoint East

Period and Type of Contract	**MMMBtus**	**Swaps Weighted Average**
July 2010 - December 2010		
Basis swaps	3,600	$ (0.62)

Derivative Fair Value Gain (Loss)

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

	Three months ended June 30,		**Six months ended June 30,**	
In thousands	**2010**	**2009**	**2010**	**2009**
Realized gain (loss) on derivatives:				

Crude oil fixed price swaps	$ 4,898	$	$ 7,430	$
Crude oil collars	1,059		1,059	
Natural gas fixed price swaps	7,534		10,255	
Natural gas basis swaps	(688)		(1,649)	
Unrealized gain (loss) on derivatives:				
Crude oil fixed price swaps	13,023		10,811	
Crude oil collars	39,634		35,085	
Natural gas fixed price swaps	(11,031)	1,835	17,294	1,835
Natural gas basis swaps	1,036	(945)	1,524	(945)
Gain on mark-to-market derivative instruments	$ 55,465	$ 890	$ 81,809	$ 890

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The table below provides data about the fair value of derivatives that are not accounted for using hedge accounting. Derivative contracts are carried at their fair value on the consolidated balance sheets under the captions Derivative assets , Noncurrent derivative assets and Accrued liabilities and other.

	June 30, 2010			December 31, 2009		
In thousands	Assets Fair Value	(Liabilities) Fair Value	Net Fair Value	Assets Fair Value	(Liabilities) Fair Value	Net Fair Value
Commodity swaps and collars	$ 62,625	$	$ 62,625	$ 2,218	$ (4,307)	$ (2,089)

Note 6. Fair Value Measurements

In January 2010, the Financial Accounting Standards Board (the FASB) issued ASU No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements*, which requires new disclosures and clarifies existing disclosure requirements related to fair value measurements. The Company adopted the applicable provisions of this new standard on January 1, 2010 and has included the required disclosures below, as applicable.

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. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available.

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 fixed price and basis swaps, due to the unavailability of relevant comparable market data for the Company s 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 fixed price and basis swap derivatives is calculated using mainly significant observable inputs (Level 2). The calculation of the fair value of collar contracts requires the use of an option-pricing model with significant unobservable inputs (Level 3). The valuation model for option derivative contracts is primarily an industry-standard model that considers various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company s calculation for each position is then compared to the counterparty valuation for reasonableness.

The following table summarizes the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of June 30, 2010. There were no transfers between Level 1 and Level 2 of the fair value hierarchy during the three and six month periods ended June 30, 2010. Further, there were no transfers in and/or out of Level 3 of the fair value hierarchy during the three and six month periods ended June 30, 2010.

	Fair value measurements at June 30, 2010 using:			
Description *In thousands*	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$	$ 31,886	$	$ 31,886
Basis swaps		(1,071)		(1,071)
Collars			31,810	31,810
Total	$	$ 30,815	$ 31,810	$ 62,625

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The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the indicated period:

In thousands	**2010**
Balance at December 31, 2009	$ (3,275)
Total realized or unrealized gains (losses):	
Included in earnings	(4,549)
Included in other comprehensive income	
Purchases, sales, issuances and settlements, net	
Transfers into Level 3	
Transfers out of Level 3	
Balance at March 31, 2010	$ (7,824)
Total realized or unrealized gains (losses):	
Included in earnings	39,634
Included in other comprehensive income	
Purchases, sales, issuances and settlements, net	
Transfers into Level 3	
Transfers out of Level 3	
Balance at June 30, 2010	$ 31,810
Change in unrealized gains (losses) relating to derivatives still held at June 30, 2010	$ 35,271

Gains and losses included in earnings for the three and six month periods ended June 30, 2010 attributable to the change in unrealized gains and losses relating to derivatives held at June 30, 2010 are reported in revenues.

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 condensed consolidated financial statements. The following methods and assumptions were used to estimate the fair values.

Asset Impairments Proved crude oil and natural 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 crude oil and natural gas production, commodity prices based on commodity futures price strips, operating and development costs, and a risk-adjusted discount rate. The fair value of crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3). Higher amortization of lease costs in existing fields, capital constraints, and amortization of new fields resulted in impairment of non-producing properties of $18.8 million and $13.2 million for the three months ended June 30, 2010 and 2009, respectively and $33.0 million and $22.6 million for the six months ended June 30, 2010 and 2009, respectively.

As a result of changes in reserves and the forward futures price strip, developed oil and gas properties were reviewed for impairment at June 30, 2010. The Company determined that the carrying amounts of certain fields were not recoverable from future cash flows and, therefore, were impaired at June 30, 2010. The affected fields had a fair value of $1.0 million at June 30, 2010 resulting in $0.7 million of developed property impairments for the quarter ended June 30, 2010. A similar calculation at March 31, 2010 determined that the carrying amounts of certain fields were not recoverable from future cash flows and, therefore, were impaired. The affected fields at March 31, 2010 had no fair value resulting in $1.0 million of developed property impairments for the first quarter of 2010. Total pre-tax (non-cash) impairments related to developed crude oil and natural gas properties for the three and six months ended June 30, 2010 were $0.7 million and $1.7 million, respectively. Impairments of developed properties amounted to $10.1 million and $36.1 million for the three and six months ended June 30, 2009, respectively. Developed and non-producing property impairments are recorded under the caption Property impairments in the condensed consolidated statements of operations.

Asset Retirement Obligations The fair values of asset retirement obligations (AROs) are 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 was $0.3 million for both the three months ended June 30, 2010 and 2009 and was $0.7 million for both the six months ended June 30, 2010 and 2009, which is reflected in the caption Asset retirement obligations, net of current portion in the condensed consolidated balance sheets. The fair values of AROs are calculated using significant unobservable inputs (Level 3).

Financial Instruments Not Recorded at Fair Value

The following table sets forth the fair value of financial instruments that are not recorded at fair value in the condensed consolidated financial statements.

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In thousands	June 30, 2010 Carrying Amount	June 30, 2010 Fair Value	December 31, 2009 Carrying Amount	December 31, 2009 Fair Value
Long-term debt				
Revolving credit facility	$ 114,000	$ 114,000	$ 226,000	$ 226,000
8 1/4 % Senior Notes due 2019 (1)	297,607	315,390	297,524	315,750
7 3/8 % Senior Notes due 2020 (2)	198,237	198,240		
Total	$ 609,844	$ 627,630	$ 523,524	$ 541,750

(1) The carrying amount is net of discounts on long-term debt of ($2.4) million and ($2.5) million at June 30, 2010 and December 31, 2009, respectively.

(2) The carrying amount is net of discounts on long-term debt of ($1.8) million at June 30, 2010.

The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The fair value of the 8 1/4% Senior Notes due 2019 and the 7 3/8% Senior Notes due 2020 are based on quoted market prices.

The carrying values of all classes of cash and cash equivalents, trade receivables, and trade payables are considered to be representative of their respective fair values due to the short term maturities of these instruments.

Note 7. Long-term Debt

Long-term debt consists of the following:

In thousands	June 30, 2010	December 31, 2009
Revolving credit facility	$ 114,000	$ 226,000
8 1/4 % Senior Notes due 2019 (1)	297,607	297,524
7 3/8 % Senior Notes due 2020 (2)	198,237	
Total long-term debt	$ 609,844	$ 523,524

(1) The carrying amount is net of discounts on long-term debt of ($2.4) million and ($2.5) million at June 30, 2010 and December 31, 2009, respectively.

(2) The carrying amount is net of discounts on long-term debt of ($1.8) million at June 30, 2010.

Revolving credit facility On June 30, 2010, the Company entered into an amended and restated revolving credit agreement (the Restated Credit Agreement). The Restated Credit Agreement amended and restated the previous credit agreement to, among other things:

Increase the maximum size of the revolving credit facility to $2.5 billion from $750 million;

Maintain aggregate commitments under the revolving credit facility of $750 million, which may be increased at the Company s option from time to time (provided no default exists) up to the lesser of $2.5 billion or the borrowing base then in effect;

Increase the borrowing base from $1.0 billion to $1.3 billion, subject to semi-annual redetermination;

Modify the applicable margin for Eurodollar and reference rate advances. Eurodollar margins range from 1.75% to 2.75% and reference rate margins range from 0.75% to 1.75% based on the amount of total outstanding borrowings in relation to the borrowing base; and

Extend the maturity of the revolving credit facility from April 12, 2011 to July 1, 2015.

Borrowings under the Restated Credit Agreement are secured by an interest in at least 85% (by value) of all of the Company s proven reserves and associated crude oil and natural gas properties. Borrowings are subject to varying rates of interest based on the total outstanding borrowings in relation to the borrowing base and whether the loan is a Eurodollar advance, a reference rate advance or a swing line advance. The Company had $114.0 million of outstanding borrowings on the amended revolving credit facility at June 30, 2010. The Company s weighted average interest rate on this debt was 2.52% at June 30, 2010.

The Company had $634.5 million of unused commitments under the revolving credit facility at June 30, 2010 and incurs commitment fees of 0.50% per annum of the daily average amount of unused borrowing availability. The Restated Credit Agreement contains certain restrictive covenants including a requirement that the Company maintain a current ratio of not less than 1.0 to 1.0 (inclusive of available borrowing capacity under the Restated Credit Agreement) and a ratio of total funded debt to EBITDAX of no greater than 3.75 to 1.0. The Company was in compliance with all covenants at June 30, 2010.

8 1/4% Senior Subordinated Notes due 2019 On September 23, 2009, the Company issued Senior Notes due 2019 (the 2019 Notes), which carry an interest rate of 8.25% and 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 initial purchasers discounts and offering expenses. The net proceeds were used to repay a portion of the borrowings outstanding under the revolving credit facility.

The 2019 Notes will mature on October 1, 2019, and interest is payable semi-annually on April 1 and October 1 of each year, commencing April 1, 2010. The Company has the option to redeem all or a portion of the 2019 Notes at any time on or after October 1, 2014 at the redemption price specified in the Indenture dated September 23, 2009 (the 2009 Indenture) plus accrued and unpaid interest. The Company may also redeem the 2019 Notes, in whole or in part, at a make-whole redemption price specified in the 2009 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 2019 Notes prior to October 1, 2012 under certain circumstances with the net cash proceeds from certain equity offerings.

7 3/8% Senior Subordinated Notes due 2020 On April 5, 2010, the Company issued $200 million of 7 3/8% Senior Notes due 2020 (the 2020 Notes). The 2020 Notes, which carry an interest rate of 7.375%, were sold at a discount (99.105% of par), which equates to an effective yield to maturity of approximately 7.50%. The 2020 Notes were offered and sold in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended (the Securities Act), and were sold to qualified institutional buyers in reliance on Rule 144A of the Securities Act. The Company received net proceeds of approximately $194.2 million after deducting the initial purchasers discounts of approximately $1.8 million and initial purchasers fees of approximately $4.0 million. The net proceeds were used to repay a portion of the borrowings outstanding under the revolving credit facility.

The 2020 Notes will mature on October 1, 2020, and interest is payable on the 2020 Notes semi-annually on April 1 and October 1 of each year, commencing on October 1, 2010. The Company has the option to redeem all or a portion of the 2020 Notes at any time on or after October 1, 2015 at the redemption prices specified in the Indenture dated April 5, 2010 (the 2010 Indenture and together with the 2009 Indenture, the Indentures) plus accrued and unpaid interest. The Company may also redeem the 2020 Notes, in whole or in part, at a make-whole redemption price specified in the 2010 Indenture, plus accrued and unpaid interest, at any time prior to October 1, 2015. In addition, the Company may redeem up to 35% of the 2020 Notes prior to October 1, 2013 under certain circumstances with the net cash proceeds from certain equity offerings.

In connection with the issuance and sale of the 2020 Notes, the Company entered into a registration rights agreement (the Registration Rights Agreement) with the initial purchasers dated April 5, 2010. Pursuant to the Registration Rights Agreement, the Company has agreed to file a registration statement with the SEC so that holders of the 2020 Notes can exchange the 2020 Notes for registered notes that have substantially identical terms as the 2020 Notes. The Company has agreed to use reasonable effort to cause the exchange to be completed within 400 days after the April 5, 2010 issuance of the 2020 Notes. The Company is required to pay additional interest if it fails to comply with its obligations to register the 2020 Notes within the specified time period, whereby the interest rate on the 2020 Notes would be increased by 1.0% per annum during the period in which a registration default is in effect. The Company expects to comply with the terms of the Registration Rights Agreement and complete the exchange of the 2020 Notes within the 400 day period.

The Indentures for the 2019 Notes and 2020 Notes (together, the Notes) contain certain restrictions on the Company s ability to incur additional debt, pay dividends on common stock, make certain investments, create certain liens on assets, engage in certain transactions with affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of the Company s assets. These covenants are subject to a number of important exceptions and qualifications. The Notes are not subject to any sinking fund requirements. The Company s sole subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees the Notes.

Note 8. Commitments and Contingencies

Drilling Commitments. As of June 30, 2010, the Company had one drilling contract that expires in August 2011. This commitment is not recorded in the accompanying consolidated balance sheets. Future commitments as of June 30, 2010 are $10.1 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 six months ended June 30, 2010 and the year ended December 31, 2009, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Expenses were $0.8 million and $0.5 million for the six months ended June 30, 2010 and 2009, respectively.

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 thresholds 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. The accrued liability for health and workers compensation claims was $1.3 million at both June 30, 2010 and December 31, 2009.

Litigation. The Company is involved in various legal proceedings in the normal course of business, none of which, in the opinion of management, will individually or collectively have a material adverse effect on the financial position or results of operations of the Company.

As of June 30, 2010 and December 31, 2009, the Company has provided a reserve of $4.5 million and $4.3 million, respectively, for various matters, none of which are believed to be individually significant.

Environmental Risk. Due to the nature of the crude oil and natural gas business, the Company is exposed to possible environmental risks. The Company is not aware of any material environmental issues or claims.

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Note 9. Stock-Based 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 $3.1 million for the three months ended June 30, 2010 and $2.7 million for the three months ended June 30, 2009. The Company s associated compensation expense included in general and administrative expense was $6.0 million for the six months ended June 30, 2010 and $5.4 million for the six months ended June 30, 2009.

Stock Options

Effective October 1, 2000, the Company adopted the 2000 Plan and granted options to certain eligible employees. These grants consisted of either incentive stock options, nonqualified stock options or a combination of both. The granted stock options vest ratably over either a three or five-year period commencing on the first anniversary of the grant date and expire ten years from date of grant. On November 10, 2005, the 2000 Plan was terminated. As of June 30, 2010, options covering 2,005,973 shares had been exercised and 478,496 had been cancelled.

The Company s stock option activity under the 2000 Plan for the six months ended June 30, 2010 was as follows:

	Outstanding		Exercisable	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding at December 31, 2009	312,190	$ 1.06	312,190	$ 1.06
Exercised	(4,500)	0.71	(4,500)	0.71
Outstanding at June 30, 2010	307,690	1.06	307,690	1.06

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option at its exercise date. The total intrinsic value of options exercised during the six months ended June 30, 2010 was approximately $0.2 million. At June 30, 2010, all options were exercisable and had a weighted average remaining life of 0.8 years with an aggregate intrinsic value of $13.4 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 June 30, 2010, the Company had 3,291,463 shares of restricted stock available to grant to directors, officers and key employees under the 2005 Plan. Restricted stock is awarded in the name of the recipient and except for the right of disposal, constitutes issued and outstanding shares of the Company s common stock for all corporate purposes during the period of restriction including the right to receive dividends, subject to forfeiture. Restricted stock grants vest over periods ranging from one to three years.

The Company began issuing shares of restricted common stock to employees and non-employee directors in October 2005. A summary of changes in the non-vested shares of restricted stock for the six months ended June 30, 2010 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares at December 31, 2009	1,126,821	$ 26.55
Granted	46,343	40.84
Vested	(84,051)	31.07
Forfeited	(25,709)	32.00
Non-vested restricted shares at June 30, 2010	1,063,404	26.68

The fair value of the restricted shares that vested during the six months ended June 30, 2010 at their vesting date was $3.8 million. As of June 30, 2010, there was $15.0 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.2 years.

Note 10. Asset Disposition

In June 2010, the Company sold certain non-strategic leaseholds located in DeSoto Parish, Louisiana to a third party with an effective date of June 18, 2010. Total cash proceeds amounted to $35.4 million, of which $17.7 million was received in June 2010 and the remaining $17.7 million is expected to be received during the third quarter of 2010. In connection with the sale, the Company recognized a pre-tax gain of $32.2 million. The sale involved undeveloped acreage with no proved reserves and no current production or revenues. The Company will use the proceeds from the sale to fund a portion of its 2010 capital expenditures program.

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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, 2009. Our operating results for the periods discussed may not be indicative of future performance. The following discussion and analysis includes forward-looking statements and should be read in conjunction with Risk Factors under Item 1A of this report, along with Cautionary Statement Regarding Forward-Looking Statements at the beginning of this report, for information about the risks and uncertainties that could cause our actual results to be materially different than our forward-looking statements.

Overview

We are engaged in crude oil and natural gas exploration, exploitation and production activities in the North, South and East regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce crude oil and natural gas reserves from unconventional formations. We derive the majority of our operating income and cash flows from the sale of crude 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 crude oil and natural gas production. In recent months and years, there has been significant volatility in crude oil and natural gas prices due to a variety of factors we cannot control or predict, including political and economic events, weather conditions, and competition from other energy sources. These factors impact supply and demand for crude oil and natural gas, which affects crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by location differences in market prices.

For the first six months of 2010, our crude oil and natural gas production increased to 7,273 MBoe (40,180 Boe per day), up 562 MBoe, or 8%, from the first six months of 2009. The increase in 2010 production was primarily driven by an increase in production from our Bakken field. Our crude oil and natural gas revenues for the first six months of 2010 increased 83% to $436.5 million due to a 62% increase in commodity prices compared to the same period in 2009. Our realized price per Boe increased $22.93 to $59.92 for the six months ended June 30, 2010 compared to the six months ended June 30, 2009. For the six month period ended June 30, 2010, we experienced increases in production taxes and other expenses of $15.8 million, or 86%, compared to the first six months of 2009, due to an increase in commodity prices and an increase in sales volumes. At various times, we have stored crude 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. For the six months ended June 30, 2010, crude oil sales volumes were 13 MBbls more than crude oil production, and crude oil sales volumes were 251 MBbls less than crude oil production for the same period in 2009. Our cash flows from operating activities for the six months ended June 30, 2010 were $390.2 million, an increase of $307.7 million from $82.5 million provided by our operating activities during the comparable 2009 period. The increase in operating cash flows was primarily due to increases in revenue as a result of higher commodity prices. During the six months ended June 30, 2010, we invested $526.3 million (including increased accruals of $40.5 million and $1.9 million of seismic costs) in our capital program concentrating mainly in the Bakken field, the Arkoma and Anadarko Woodford plays, and the Red River units.

In July 2010, our Board of Directors increased our 2010 capital expenditures budget to $1.3 billion to accelerate our drilling program and increase our acreage positions in strategic plays in the United States. Our previous 2010 capital expenditures budget was $850 million. Our revised 2010 capital expenditures budget of $1.3 billion will primarily focus on increased development in the Bakken shale of North Dakota and Montana, the Anadarko Woodford shale in western Oklahoma, and the Niobrara shale in Colorado and Wyoming. We expect our cash flows from operations and the availability under our revolving credit facility will be sufficient to meet our capital expenditure needs. Continued strength in commodity prices may result in an increase in our actual capital expenditures during 2010; conversely, a significant decline in product prices could result in a decrease in our capital expenditures.

How We Evaluate Our Operations

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

volumes of crude oil and natural gas produced,

crude 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 June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Average daily production:				
Crude oil (Bopd)	31,611	27,654	30,373	27,119
Natural gas (Mcfd)	61,815	58,156	58,844	59,760
Crude oil equivalents (Boepd)	41,913	37,347	40,180	37,079
Average prices: (1)				
Crude oil ($/Bbl)	$ 68.44	$ 53.44	$ 69.87	$ 44.82
Natural gas ($/Mcf)	4.33	2.60	4.84	2.79
Crude oil equivalents ($/Boe)	57.94	43.52	59.92	36.99
Production expense ($/Boe) (1)	5.90	7.14	6.17	7.19
General and administrative expense ($/Boe) (1)	3.03	2.78	3.20	3.04
EBITDAX (in thousands) (2)	211,611	106,250	391,578	163,923
Net income (loss) (in thousands)	101,741	13,508	174,206	(13,105)
Diluted net income (loss) per share	0.60	0.08	1.03	(0.08)

(1) Average prices and per unit expenses have been calculated using sales volumes and excluding any effect of derivative transactions. At various times, we have stored crude 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. Crude oil sales volumes were 28 MBbls less than crude oil production for the three months ended June 30, 2010 and 35 MBbls less than crude oil production for the three months ended June 30, 2009. For the six months ended June 30, 2010, crude oil sales volumes were 13 MBbls more than crude oil production and 251 MBbls less than crude oil production for the six months ended June 30, 2009.

(2) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows as determined by U.S. GAAP. A reconciliation of net income to EBITDAX is provided subsequently under the header *Non-GAAP Financial Measures*.

Three months ended June 30, 2010 compared to the three months ended June 30, 2009

Results of Operations

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

	Three months ended June 30,	
In thousands, except price data	2010	2009
Crude oil and natural gas sales	$ 219,426	$ 146,439
Gain on mark-to-market derivative instruments	55,465	890
Total revenues	279,968	151,761
Operating costs and expenses (1)	103,645	125,580
Other expenses, net	11,825	4,422
Income before income taxes	164,498	21,759
Provision for income taxes	62,757	8,251
Net income	$ 101,741	$ 13,508
Production Volumes:		
Crude oil (MBbl)	2,877	2,517
Natural gas (MMcf)	5,625	5,293
Crude oil equivalents (MBoe)	3,815	3,398

Sales Volumes:				
Crude oil (MBbl)		2,849		2,482
Natural gas (MMcf)		5,625		5,293
Crude oil equivalents (MBoe)		3,788		3,365
Average Prices: (2)				
Crude oil ($/Bbl)	$	68.44	$	53.44
Natural gas ($/Mcf)	$	4.33	$	2.60
Crude oil equivalents ($/Boe)	$	57.94	$	43.52

(1) Net of gain on sale of assets of $33.1 million and $0.1 million for the three months ended June 30, 2010 and 2009, respectively.

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

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Production

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

	Three months ended June 30, 2010		2009		Volume	Percent
	Volume	Percent	Volume	Percent	increase	increase
Crude oil (MBbl)	2,877	75%	2,517	74%	360	14%
Natural Gas (MMcf)	5,625	25%	5,293	26%	332	6%
Total (MBoe)	3,815	100%	3,398	100%	417	12%

	Three months ended June 30, 2010		2009		Volume increase	Percent increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
North Region	3,033	80%	2,585	76%	448	17%
South Region	675	17%	680	20%	(5)	(1)%
East Region	107	3%	133	4%	(26)	(20)%
Total (MBoe)	3,815	100%	3,398	100%	417	12%

Crude oil production volumes increased 14% during the three months ended June 30, 2010 compared to the three months ended June 30, 2009. Production increases in the North Dakota Bakken field, Red River units, and the Oklahoma Woodford contributed incremental volumes in 2010 of 520 MBbls in excess of production for the second quarter of 2009. Favorable results from drilling have been the primary contributors to production growth in these areas. This increase was partially offset by a decrease of 128 MBbls in the Montana Bakken due to wells shut in for repairs and natural declines. Natural gas volumes increased 332 MMcf, or 6%, during the three months ended June 30, 2010 compared to the same period in 2009. Natural gas production in the Bakken field in the North region was up 609 MMcf for the three months ended June 30, 2010 compared to the same period in 2009 due to additional natural gas being connected and sold in North Dakota. These additional sales in the Bakken field were partially offset by decreases in natural gas volumes of 193 MMcf in the Cedar Hills field due to the conversion to water floods and 60 MMcf in the South region due to natural declines.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the three months ended June 30, 2010 were $219.4 million, a 50% increase from sales of $146.4 million for the same period in 2009. Our sales volumes increased 423 MBoe, or 13%, over the same period in 2009 due to the continuing success of our enhanced crude oil recovery and drilling programs. Our realized price per Boe increased $14.42 to $57.94 for the three months ended June 30, 2010 from $43.52 for the three months ended June 30, 2009. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended June 30, 2010 was $9.59 compared to $6.02 for the three months ended June 30, 2009 and $8.29 for the year ended December 31, 2009. Factors contributing to the changing differentials included Canadian crude oil imports and increases in production in the North region, coupled with downstream transportation capacity and seasonal demand fluctuations for gasoline.

Derivatives. We are 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 mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value on derivative instruments in the statements of operations under the caption Gain on mark-to-market derivative instruments.

During the three months ended June 30, 2010, we realized gains on natural gas derivatives of $6.8 million and realized gains on crude oil derivatives of $6.0 million. During the three months ended June 30, 2010, we reported an unrealized non-cash mark-to-market loss on natural gas derivatives of $10.0 million and an unrealized non-cash mark-to-market gain on crude oil derivatives of $52.7 million. During the three months ended June 30, 2009, our crude oil production was unhedged and we reported non-cash unrealized mark-to-market gains from our gas derivatives of $0.9 million for such period.

Crude Oil and Natural Gas Service Operations. Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil. Prices for reclaimed crude oil sold from our central treating units were higher for the three months ended June 30, 2010 than the comparable 2009 period. The price increased $20.70 per barrel which increased reclaimed crude oil income by $1.6 million, contributing to an overall increase in crude oil and natural gas service operations revenue of $0.6 million for the three months ended June 30, 2010. We sold high-pressure air from our Red River units to a third party and recorded revenues of $0.4 million for the three months ended June 30, 2009. Beginning January 2010, we no longer sell high-pressure air to a third party. Associated crude oil and natural gas service operations expenses increased $1.4 million to $4.1 million during the three months ended June 30, 2010 from $2.7 million during the three months ended June 30, 2009 due mainly to an increase in the costs of purchasing and treating crude oil for resale compared to the same period in 2009.

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Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses decreased 7% to $22.3 million during the three months ended June 30, 2010 from $24.0 million during the three months ended June 30, 2009. Production expense per Boe decreased to $5.90 for the three months ended June 30, 2010 from $7.14 per Boe for the three months ended June 30, 2009. In the prior year we leased compressors from a related party for approximately $400,000 per month under an operating lease and a new agreement was negotiated effective February 1, 2010 for a term of 16 months resulting in the monthly lease fee being reduced to $50,000, lowering production expense per Boe for the 2010 period. Also contributing to the decrease was a non-recurring charge recorded in the prior year period to accrue for potential loss exposure on royalty disputes.

Production taxes and other expenses increased $6.6 million, or 57%, during the three months ended June 30, 2010 compared to the three months ended June 30, 2009 as a result of higher revenues resulting from increased sales prices and the expiration of various tax incentives. Production taxes and other expenses in the unaudited condensed consolidated statements of operations includes other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma area of $1.6 million and $2.3 million for the three months ended June 30, 2010 and 2009, respectively. Production taxes, excluding other charges, as a percentage of crude oil and natural gas sales, were 7.4% for the three months ended June 30, 2010 compared to 6.4% for the three months ended June 30, 2009. The increase is due to oil extraction tax incentives in North Dakota realized during the three months ended June 30, 2009, no longer being applicable to wells completed in 2010, causing higher tax rates on production from this area where we are most active. 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 crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana 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 expenses and production taxes and other expenses were as follows:

	Three months ended June 30,		Percent
$/Boe	**2010**	**2009**	**increase (decrease)**
Production expenses	$ 5.90	$ 7.14	(17)%
Production taxes and other expenses	4.81	3.46	39%
Production expenses, production taxes and other expenses	$ 10.71	$ 10.60	1%

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $0.7 million in the three months ended June 30, 2010 to $2.3 million due primarily to increases in seismic expense of $0.5 million and dry hole expense of $0.2 million.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $5.7 million, or 11%, in the second quarter of 2010 compared to the second quarter of 2009, primarily due to the increase in production. The following table shows the components of our DD&A rate per Boe.

	Three months ended June 30,	
$/Boe	**2010**	**2009**
Crude oil and natural gas	$ 15.12	$ 15.40
Other equipment	0.24	0.23
Asset retirement obligation accretion	0.17	0.17
Depreciation, depletion, amortization and accretion	$ 15.53	$ 15.80

DD&A per Boe decreased partially as a result of the increase in commodity prices used to calculate year-end 2009 reserve volumes as compared to the prices used to calculate year-end 2008 reserve volumes. Higher prices have the effect of increasing the economic life of oil and gas properties, which increases future reserve volumes and decreases DD&A on a volumetric basis. Additionally, our costs of adding new reserves in the Bakken field have been lower in 2010 compared to our historical averages, resulting in lower DD&A rates being applied to production in that area compared to the prior year.

Property Impairments. Property impairments, non-producing and developed, decreased in the three months ended June 30, 2010 by $3.8 million to $19.5 million compared to $23.3 million during the three months ended June 30, 2009.

Impairment of non-producing properties increased $5.6 million during the three months ended June 30, 2010 to $18.8 million compared to $13.2 million for the three months ended June 30, 2009 reflecting amortization of new fields and higher amortization of lease costs in our existing fields resulting from further defining likely drilling locations and capital constraints. 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 crude oil and natural gas properties were approximately $0.7 million for the three months ended June 30, 2010 compared to approximately $10.1 million for the three months ended June 30, 2009, a decrease of $9.4 million, or 93%. We evaluate our developed crude oil and natural 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

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of fair market value based on discounted cash flows. Impairments of developed properties in 2010 reflect uneconomic operating results in the East region, which resulted in impairments of $0.7 million for the three months ended June 30, 2010. Impairments of developed properties in 2009 reflect uneconomic drilling results primarily in our South region, which resulted in impairments of $10.0 million.

General and Administrative Expenses. General and administrative expenses increased $2.1 million to $11.5 million during the three months ended June 30, 2010 from $9.4 million during the comparable period in 2009. The majority of the increase was in personnel and office expenses. General and administrative expenses include non-cash charges for stock-based compensation of $3.1 million and $2.7 million for the three months ended June 30, 2010 and 2009, respectively. General and administrative expenses excluding stock-based compensation increased $1.7 million for the three months ended June 30, 2010 compared to the same period in 2009. On a volumetric basis, general and administrative expenses increased $0.25 to $3.03 per Boe for the three months ended June 30, 2010 compared to $2.78 per Boe for the three months ended June 30, 2009.

Interest Expense. Interest expense increased 152%, or $7.2 million, for the three months ended June 30, 2010 compared to the three months ended June 30, 2009, due to higher interest rates on the Notes compared to our credit facility borrowings in the prior year, along with an increase in our outstanding debt balance. On September 23, 2009, we issued $300.0 million of 2019 Notes, which carry an interest rate of 8.25% and were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. On April 5, 2010, we issued $200.0 million of 7 ^{3}/8% Senior Notes due 2020 (the 2020 Notes), which carry an interest rate of 7.375% and were sold at a discount (99.105% of par), which equates to an effective yield to maturity of approximately 7.5%. We recorded $9.7 million in interest expense on the 2019 Notes and the 2020 Notes for the three months ended June 30, 2010. Including the interest on the Notes our weighted average interest rate for the three months ended June 30, 2010 was 7.1% while for the three months ended June 30, 2009 our weighted average rate was 2.72%.

Our average revolving credit facility balance decreased to $98.7 million for the three months ended June 30, 2010 compared to $612.6 million for the three months ended June 30, 2009, and the weighted average interest rate on our revolving credit facility was lower at 2.43% for the three months ended June 30, 2010 compared to 2.72% for the same period in 2009. At June 30, 2010, our outstanding revolving credit facility balance was $114.0 million with a weighted average interest rate of 2.52%.

Income Taxes. We recorded income tax expense for the three months ended June 30, 2010 of $62.8 million compared to $8.3 million for the three months ended June 30, 2009. We provide taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

Six months ended June 30, 2010 compared to the six months ended June 30, 2009

Results of Operations

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

	Six months ended June 30,	
In thousands, except price data	**2010**	**2009**
Crude oil and natural gas sales	$ 436,550	$ 239,007
Gain on mark-to-market derivative instruments	81,809	890
Total revenues	528,236	248,369
Operating costs and expenses [(1)]	227,384	260,620
Other expenses, net	19,479	8,862
Income (loss) before income taxes	281,373	(21,113)
Provision (benefit) for income taxes	107,167	(8,008)
Net income (loss)	$ 174,206	$ (13,105)
Production Volumes:		
Crude oil (MBbl)	5,497	4,909
Natural gas (MMcf)	10,651	10,817
Crude oil equivalents (MBoe)	7,273	6,711
Sales Volumes:		
Crude oil (MBbl)	5,510	4,658

Natural gas (MMcf)	10,651	10,817
Crude oil equivalents (MBoe)	7,286	6,461
Average Prices: [2]		
Crude oil ($/Bbl)	$ 69.87	$ 44.82
Natural gas ($/Mcf)	$ 4.84	$ 2.79
Crude oil equivalents ($/Boe)	$ 59.92	$ 36.99

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(1) Net of gain on sale of assets of $33.3 million and $0.2 million for the six months ended June 30, 2010 and 2009, respectively.
(2) Average prices have been calculated using sales volumes and excluding any effect of derivative transactions.

Production

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

	Six months ended June 30, 2010		2009		Volume	Percent
	Volume	Percent	Volume	Percent	increase (decrease)	increase (decrease)
Crude oil (MBbl)	5,497	76%	4,909	73%	588	12%
Natural Gas (MMcf)	10,651	24%	10,817	27%	(166)	(2)%
Total (MBoe)	7,273	100%	6,711	100%	562	8%

	Six months ended June 30, 2010		2009		Volume	Percent
	MBoe	Percent	MBoe	Percent	increase (decrease)	increase (decrease)
North Region	5,739	79%	5,027	75%	712	14%
South Region	1,303	18%	1,430	21%	(127)	(9)%
East Region	231	3%	254	4%	(23)	(9)%
Total (MBoe)	7,273	100%	6,711	100%	562	8%

Crude oil production volumes increased 12% during the six months ended June 30, 2010 compared to the six months ended June 30, 2009. Production increases in the North Dakota Bakken field, Cedar Hills field and the Oklahoma Woodford contributed incremental volumes in 2010 of 941 MBbls in excess of production for the same period in 2009. Favorable results from drilling have been the primary contributors to production growth in these areas. This increase was partially offset by a decrease in the Montana Bakken of 234 MBbls due to wells shut in for repairs and natural declines. Natural gas volumes decreased 166 MMcf, or 2%, during the six months ended June 30, 2010 compared to the same period in 2009. Natural gas production in the Bakken field in the North region was up 1,178 MMcf for the six months ended June 30, 2010 compared to the same period in 2009 due to additional natural gas being connected and sold in North Dakota. These additional sales in North Dakota were offset by a decrease in natural gas volumes of 548 MMcf in the Red River units due to the conversion to water floods and the Badlands plant being down for repairs. Further, the South region natural gas volumes decreased 791 MMcf mostly due to natural declines from a non-Woodford area.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the six months ended June 30, 2010 were $436.5 million, an 83% increase from sales of $239.0 million for the same period in 2009. Our sales volumes increased 825 MBoe, or 13%, over the same period in 2009 due to the continuing success of our enhanced crude oil recovery and drilling programs. Our realized price per Boe increased $22.93 to $59.92 for the six months ended June 30, 2010 from $36.99 for the six months ended June 30, 2009. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the six months ended June 30, 2010 was $8.54 compared to $7.08 for the six months ended June 30, 2009 and $8.29 for the year ended December 31, 2009. Factors contributing to the changing differentials included Canadian crude oil imports and increases in production in the North region, coupled with downstream transportation capacity and seasonal demand fluctuations for gasoline.

Derivatives. We are 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 mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value on derivative instruments in the statements of operations under the caption Gain on mark-to-market derivative instruments.

During the six months ended June 30, 2010, we realized gains on natural gas derivatives of $8.6 million and realized gains on crude oil derivatives of $8.5 million. During the six months ended June 30, 2010, we reported an unrealized non-cash mark-to-market gain on natural gas derivatives of $18.8 million and an unrealized non-cash mark-to-market gain on crude oil derivatives of $45.9 million. During the six months ended June 30, 2009, our crude oil production was unhedged and we reported non-cash unrealized mark-to-market gains from our gas derivatives of $0.9 million for such period.

Crude Oil and Natural Gas Service Operations. Our crude oil and natural gas service operations consist primarily of the treatment and sale of lower quality crude oil, or reclaimed crude oil. Prices for reclaimed crude oil sold from our central treating units were higher for the six months ended June 30, 2010 than the comparable 2009 period. The price increased $29.05 per barrel which increased reclaimed crude oil income by $3.4 million, contributing to an overall increase in crude oil and natural gas service operations revenue of $1.4 million for the six months ended June 30, 2010. We sold high-pressure air from our Red River units to a third party and recorded revenues of $1.1 million for the six months ended June 30, 2009. Beginning January 2010, we no longer sell high-pressure air to a third party. Associated crude oil and natural gas service operations expenses increased $2.9 million to $8.0

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million during the six months ended June 30, 2010 from $5.1 million during the six months ended June 30, 2009 due mainly to an increase in the costs of purchasing and treating crude oil for resale compared to the same period in 2009.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses decreased 3% to $44.9 million during the six months ended June 30, 2010 from $46.5 million during the six months ended June 30, 2009. Production expenses per Boe decreased to $6.17 for the six months ended June 30, 2010 from $7.19 per Boe for the six months ended June 30, 2009. In the prior year we leased compressors from a related party for approximately $400,000 per month under an operating lease and a new agreement was negotiated effective February 1, 2010 for a term of 16 months resulting in the monthly lease fee being reduced to $50,000, lowering production expense per Boe for the 2010 period. Also contributing to the decrease was a non-recurring charge recorded in the prior year period to accrue for potential loss exposure on royalty disputes.

Production taxes and other expenses increased $15.8 million, or 86%, during the six months ended June 30, 2010 compared to the six months ended June 30, 2009 as a result of higher revenues resulting from increased sales prices and the expiration of various tax incentives. Production taxes and other expenses in the unaudited condensed consolidated statements of operations include other charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma area of $2.9 million and $3.5 million for the six months ended June 30, 2010 and 2009, respectively. Production taxes, excluding other charges, as a percentage of crude oil and natural gas sales were 7.2% for the six months ended June 30, 2010 compared to 6.3% for the six months ended June 30, 2009. The increase is due to oil extraction tax incentives in North Dakota realized during the six months ended June 30, 2009, no longer being applicable to wells completed in 2010, causing higher tax rates on production from this area where we are most active. 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 crude oil or natural gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana 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 expenses and production taxes and other expenses were as follows:

	Six months ended June 30,		Percent increase
$/Boe	**2010**	**2009**	**(decrease)**
Production expenses	$ 6.17	$ 7.19	(14)%
Production taxes and other expenses	4.70	2.86	64%
Production expenses, production taxes and other expenses	$ 10.87	$ 10.05	8%

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses decreased $4.6 million in the six months ended June 30, 2010 to $4.1 million due primarily to a decrease in dry hole expense of $4.6 million.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $7.6 million, or 7%, in the first six months of 2010 compared to the same period in 2009, primarily due to the increase in production. The following table shows the components of our DD&A rate per Boe.

	Six months ended June 30,	
$/Boe	**2010**	**2009**
Crude oil and natural gas	$ 14.88	$ 15.66
Other equipment	0.23	0.24
Asset retirement obligation accretion	0.18	0.17
Depreciation, depletion, amortization and accretion	$ 15.29	$ 16.07

DD&A per Boe decreased partially as a result of the increase in commodity prices used to calculate year-end 2009 reserve volumes as compared to the prices used to calculate year-end 2008 reserve volumes. Higher prices have the effect of increasing the economic life of oil and gas properties, which increases future reserve volumes and decreases DD&A on a volumetric basis. Additionally, our costs of adding new reserves in the Bakken field have been lower in 2010 compared to our historical averages, resulting in lower DD&A rates being applied to production in that area compared to the prior year.

Property Impairments. Property impairments, non-producing and developed, decreased in the six months ended June 30, 2010 by $24.0 million to $34.7 million compared to $58.7 million during the six months ended June 30, 2009.

Impairment of non-producing properties increased $10.4 million during the six months ended June 30, 2010 to $33.0 million compared to $22.6 million for the six months ended June 30, 2009 reflecting amortization of new fields and higher amortization of lease costs in our existing fields resulting from further defining likely drilling locations and capital constraints. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period.

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Impairment provisions for developed crude oil and natural gas properties were approximately $1.7 million for the six months ended June 30, 2010 compared to approximately $36.1 million for the six months ended June 30, 2009, a decrease of $34.4 million, or 95%. We evaluate our developed crude oil and natural 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 of developed properties in 2010 reflect uneconomic operating results in the East region and a non-Bakken Montana field in the North region, which resulted in impairments of $1.7 million for the six months ended June 30, 2010. Impairments of developed properties in 2009 reflect uneconomic drilling results in three single well fields completed in the first half of 2009 in our South region, which resulted in impairments of $24.8 million. The remaining 2009 impairments were $4.1 million in the East region and $7.2 in the North region due to decreases in reserves and prices.

General and Administrative Expenses. General and administrative expenses increased $3.7 million to $23.3 million during the six months ended June 30, 2010 from $19.6 million during the comparable period in 2009. The majority of the increase was in personnel and office expenses. General and administrative expenses include non-cash charges for stock-based compensation of $6.0 million and $5.4 million for the six months ended June 30, 2010 and 2009, respectively. General and administrative expenses excluding stock-based compensation increased $3.1 million for the six months ended June 30, 2010 compared to the same period in 2009. On a volumetric basis, general and administrative expenses increased $0.16 to $3.20 per Boe for the six months ended June 30, 2010 compared to $3.04 per Boe for the six months ended June 30, 2009.

Interest Expense. Interest expense increased 118%, or $11.0 million, for the six months ended June 30, 2010 compared to the six months ended June 30, 2009, due to higher interest rates on the Notes compared to our revolving credit facility borrowings in the prior year, along with higher debt balances. The 2019 Notes were issued on September 23, 2009 in an aggregate principal amount of $300.0 million and carry an interest rate of 8.25%. They were sold at a discount (99.16% of par), which equates to an effective yield to maturity of approximately 8.375%. The 2020 Notes were issued on April 5, 2010 in an aggregate principal amount of $200.0 million and carry an interest rate of 7.375%. They were sold at a discount (99.105% of par), which equates to an effective yield to maturity of approximately 7.5%. We recorded $15.9 million in interest expense on the Notes for the six months ended June 30, 2010. Including the interest on the Notes, our weighted average interest rate for the six months ended June 30, 2010 was 6.83% compared to 3.07% for the six months ended June 30, 2009.

Our average revolving credit facility balance decreased to $157.3 million for the six months ended June 30, 2010 compared to $546.6 million for the six months ended June 30, 2009, and the weighted average interest rate on our revolving credit facility was lower at 2.65% for the six months ended June 30, 2010 compared to 3.07% for the same period in 2009. At June 30, 2010, our outstanding revolving credit facility balance was $114.0 million with a weighted average interest rate of 2.52%.

Income Taxes. We recorded income tax expense for the six months ended June 30, 2010 of $107.2 million compared to a benefit of $8.0 million for the six months ended June 30, 2009. 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 bonds. During the first six months of 2010, crude oil prices were $22.93 higher than the first six months of 2009, and we have seen natural gas prices for the first six months of 2010 increase 73% compared to the first six months of 2009. Since crude oil accounts for more than 75% of our production, the price increase resulted in improved cash flows from operations and better liquidity.

On June 30, 2010, we entered into an amended and restated revolving credit agreement (the Restated Credit Agreement). The Restated Credit Agreement amended and restated our previous credit agreement to, among other things:

- Increase the maximum size of the revolving credit facility to $2.5 billion from $750 million;
- Maintain aggregate commitments under the revolving credit facility of $750 million, which may be increased at our option from time to time (provided there exists no default) up to the lesser of $2.5 billion or the borrowing base then in effect;
- Increase the borrowing base from $1.0 billion to $1.3 billion, subject to semi-annual redetermination;

Modify the applicable margin for Eurodollar and reference rate advances. Eurodollar margins range from 1.75% to 2.75% and reference rate margins range from 0.75% to 1.75% based on the amount of total outstanding borrowings in relation to the borrowing base; and

Extend the maturity of the revolving credit facility from April 12, 2011 to July 1, 2015.

Our amended revolving credit facility is backed by a syndicate of 14 banks. We believe that the current syndicate of banks has the capability to fund up to their commitments. If one or more banks should not be able to fund their commitment, we may not have the full availability of the $750.0 million commitment.

On September 23, 2009, we issued $300.0 million of the 2019 Notes and received net proceeds of approximately $289.7 million after deducting initial purchasers discounts and other expenses and after giving effect to the discount at which the 2019 Notes were issued. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility. On April 5, 2010, we issued $200.0 million of the 2020 Notes and received net proceeds of approximately $194.2 million after deducting initial purchasers discounts and other expenses and after giving effect to the discount at which the 2020 Notes were issued. The net proceeds from the 2020 Notes were used to repay a portion of the borrowings outstanding under our revolving credit facility. As of June 30, 2010, we had $634.5 million of borrowing availability under our revolving credit facility. As of July 31, 2010, we had $544.5 million of borrowing availability under our revolving credit facility.

In June 2010, we sold certain non-strategic leaseholds located in DeSoto Parish, Louisiana to a third party with an effective date of June 18, 2010. Total cash proceeds amounted to $35.4 million, of which $17.7 million was received in June 2010 and the remaining $17.7 million is expected to be received during the third quarter of 2010. In connection with the sale, we recognized a pre-tax gain of $32.2 million. The sale involved undeveloped acreage with no proved reserves and no current production or revenues. We will use the proceeds from the sale to fund a portion of our 2010 capital expenditures program.

We believe that funds from operating cash flows and our 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 flows from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. Furthermore, the issuance of additional debt may require that a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows 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.

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 Flows from Operating Activities

Our net cash provided by operating activities was $390.2 million and $82.5 million for the six months ended June 30, 2010 and 2009, respectively. The increase in operating cash flows was mainly due to increases in revenue as a result of higher commodity prices.

Cash Flows from Investing Activities

During the six months ended June 30, 2010 and 2009, we had cash flows used in investing activities (excluding asset sales) of $483.9 million and $297.2 million, respectively, related to our capital program, inclusive of dry hole costs. The increase in our cash flows used in investing activities was primarily due to the acceleration of our drilling program primarily in the North Dakota Bakken and Arkoma Woodford plays.

Cash Flows from Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2010 was $73.3 million and was mainly the result of the issuance of the 2020 Notes along with borrowings on our revolving credit facility, partially offset by amounts repaid under our revolving credit facility. Net cash provided by financing activities of $213.1 million for the six months ended June 30, 2009 was mainly the result of amounts borrowed under our revolving credit facility to fund capital expenditures. On April 5, 2010, we issued $200.0 million of 7 $^{3}/8$% Senior Notes due 2020 and received net proceeds of approximately $194.2 million, which were used to repay a portion of the borrowings outstanding under our revolving credit facility.

Revolving Credit Facility

We had $114.0 million and $226.0 million outstanding under our revolving credit facility at June 30, 2010 and December 31, 2009, respectively. We used the net proceeds of $194.2 million from our April 5, 2010 issuance of the 2020 Notes to repay a portion of our outstanding revolving credit facility borrowings. As of July 31, 2010, we had $204.0 million of outstanding borrowings under our revolving credit facility. The amended and restated revolving credit facility that was entered into on June 30, 2010, has an aggregate commitment level of $750 million and a borrowing base of $1.3 billion that is subject to semi-annual redetermination. We expect the next borrowing base redetermination to occur in the fourth quarter of 2010. The terms of the revolving credit facility

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provide for the commitment level to be increased at our option from time to time (provided no default exists) up to the lesser of $2.5 billion or the current borrowing base.

8 1/4% Senior Subordinated Notes due 2019

On September 23, 2009, we issued $300 million of the 2019 Notes. The 2019 Notes, which carry an interest 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%. We received net proceeds of approximately $289.7 million after deducting the initial purchasers discounts and fees. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

The 2019 Notes will mature on October 1, 2019, and interest is payable semi-annually on April 1 and October 1 of each year, commencing April 1, 2010. We have the option to redeem all or a portion of the 2019 Notes at any time on or after October 1, 2014 at the redemption price specified in the Indenture dated September 23, 2009 (the 2009 Indenture) plus accrued and unpaid interest. We may also redeem the 2019 Notes, in whole or in part, at a make-whole redemption price specified in the 2009 Indenture, plus accrued and unpaid interest, at any time prior to October 1, 2014. In addition, we may redeem up to 35% of the 2019 Notes prior to October 1, 2012 under certain circumstances with the net cash proceeds from certain equity offerings. The 2009 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. We were in compliance with these covenants as of June 30, 2010. The 2019 Notes are not subject to any sinking fund requirements. Our subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees this debt.

7 3/8% Senior Subordinated Notes due 2020

On April 5, 2010, we issued $200 million of 7 3/8% Senior Notes due 2020. The 2020 Notes, which carry an interest rate of 7.375%, were sold at a discount (99.105% of par), which equates to an effective yield to maturity of approximately 7.5%. We received net proceeds of approximately $194.2 million after deducting the initial purchasers discounts and fees. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

The 2020 Notes will mature on October 1, 2020, and interest is payable semi-annually on April 1 and October 1 of each year, commencing on October 1, 2010. We have the option to redeem all or a portion of the 2020 Notes at any time on or after October 1, 2015 at the redemption prices specified in the Indenture dated April 5, 2010 (the 2010 Indenture) plus accrued and unpaid interest. We may also redeem the 2020 Notes, in whole or in part, at a make-whole redemption price specified in the 2010 Indenture, plus accrued and unpaid interest, at any time prior to October 1, 2015. In addition, we may redeem up to 35% of the 2020 Notes prior to October 1, 2013 under certain circumstances with the net cash proceeds from certain equity offerings. The 2010 Indenture contains certain restrictions on our ability to incur additional debt, pay dividends on our common stock, make certain investments, create certain liens on our assets, engage in certain transactions with our affiliates, transfer or sell certain assets, consolidate or merge, or sell substantially all of our assets. These covenants are subject to a number of important exceptions and qualifications. We were in compliance with these covenants as of June 30, 2010. The 2020 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.

Capital Expenditures and Commitments

We evaluate opportunities to purchase or sell crude oil and natural gas properties 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.

In July 2010, our Board of Directors increased our 2010 capital expenditures budget to $1.3 billion to accelerate our drilling program and to increase our acreage positions in strategic U. S. shale plays. Our previous 2010 capital expenditures budget was $850 million.

During the first six months of 2010, we participated in the completion of 142 gross (43.4 net) wells and invested a total of $526.3 million (including increases in accruals of $40.5 million and $1.9 million of seismic costs) for capital expenditures as shown in the following table.

in millions	**Amount**
Exploration and development drilling	$ 275.1

Dry holes	0.4
Acquisition of producing properties	0.2
Capital facilities, workovers and re-completions	15.4
Land costs	219.1
Seismic	1.9
Vehicles, computers and other equipment	14.2
Total	$ 526.3

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The revised 2010 capital expenditures budget of $1.3 billion will primarily focus on increased development in the Bakken shale of North Dakota and Montana, the Anadarko Woodford shale in western Oklahoma and the Niobrara shale in Colorado and Wyoming.

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 2010 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 flows, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

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, 2009.

Non-GAAP Financial Measures

EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, unrealized derivative gains and losses, and non-cash equity compensation expense. EBITDAX is not a measure of net income or cash flows 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 flows as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our revolving credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1.0 on a rolling four-quarter basis. We were in compliance with this covenant at June 30, 2010. A violation of this covenant in the future could result in a default under our revolving credit facility. In the event of such default, the lenders under our revolving credit facility could elect to terminate their commitments thereunder, cease making further loans, and could declare all outstanding amounts, together with accrued interest, to be due and payable. If the indebtedness under our revolving credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. 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.

	Three months ended June 30,		Six months ended June 30,	
in thousands	**2010**	**2009**	**2010**	**2009**
Net income (loss)	$ 101,741	$ 13,508	$ 174,206	$ (13,105)
Interest expense	11,903	4,723	20,263	9,310
Provision (benefit) for income taxes	62,757	8,251	107,167	(8,008)
Depreciation, depletion, amortization and accretion	58,822	53,148	111,409	103,845
Property impairments	19,514	23,275	34,689	58,700
Exploration expenses	2,269	1,530	4,055	8,649
Unrealized derivative gain	(48,513)	(890)	(66,181)	(890)
Non-cash equity compensation	3,118	2,705	5,970	5,422
EBITDAX	$ 211,611	$ 106,250	$ 391,578	$ 163,923

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 crude 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 crude oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price. Based on our average daily production for the six months ended June 30, 2010, our annual revenue would increase or decrease by approximately $110.9 million for each $10.00 per barrel change in crude oil prices and $21.5 million for each $1.00 per MMBtu change in natural gas prices.

To partially reduce price risk caused by these market fluctuations, we periodically hedge crude oil and natural gas prices through the utilization of derivatives, including zero-cost collars and fixed price contracts.

During the six months ended June 30, 2010, we entered into several new swap and collar derivative contracts covering a portion of our crude oil and natural gas production for 2010 and 2011. The new contracts were entered into in the normal course of business and we expect to enter into additional similar contracts during the year. None of the new contracts have been designated for hedge accounting. See *Part I, Item 1. Financial Statements, Note 5 Derivative Contracts* for additional information regarding our swap and collar derivative contracts.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our crude oil and natural gas production, which we market to energy marketing companies, refineries and affiliates ($151.5 million in receivables at June 30, 2010) and joint interest receivables ($154.5 million at June 30, 2010). We monitor our exposure to counterparties on crude 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 crude oil and natural gas sales receivables owed to us.

Joint interest receivables arise from billing entities who own a 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.

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 $204.0 million outstanding under our revolving credit facility at July 31, 2010. The impact of a 1% increase in interest rates on this amount of debt would increase interest expense by approximately $2.0 million per year. Our revolving credit facility debt matures on July 1, 2015 and the weighted-average interest rate at July 31, 2010 was 2.29%.

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 June 30, 2010. 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 June 30, 2010, 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 have materially affected, or are 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.

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. See *Note 8. Commitments and Contingencies* in *Notes to Unaudited Condensed Consolidated Financial Statements*.

ITEM 1A. Risk Factors

There have been no material changes in our risk factors from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2009.

In addition to the other information set forth in this Form 10-Q, you should carefully consider the factors discussed in *Part I, Item 1A. Risk Factors* in our 2009 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in this Form 10-Q and in our 2009 Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

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

(a) Not applicable.

(b) Not applicable.

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

The following table provides information about purchases of equity securities that are registered by us pursuant to Section 12 of the Exchange Act during the quarter ended June 30, 2010:

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)
April 1, 2010 to April 30, 2010	4,865	$ 45.38		
May 1, 2010 to May 31, 2010	4,673	$ 47.35		
June 1, 2010 to June 30, 2010	8,683	$ 49.25		
Total	18,221	$ 47.73		

(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 9. Stock-Based 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. (Removed and Reserved)

ITEM 5. Other Information

Not applicable.

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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: August 6, 2010

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

(Duly Authorized Officer and Principal Financial Officer)

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Index to Exhibits

3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed as Exhibit 3.1 to the Company s Current Report on Form 8-K (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	Indenture dated as of April 5, 2010 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 April 7, 2010 and incorporated herein by reference.
4.2	Registration Rights Agreement dated as of April 5, 2010 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 April 7, 2010 and incorporated herein by reference.
10.1	Purchase Agreement dated as of March 30, 2010 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 April 5, 2010 and incorporated herein by reference.
10.2	Seventh Amended and Restated Credit Agreement dated June 30, 2010 among Continental Resources, Inc. as borrower, Union Bank, N.A. as administrative agent, as issuing lender and as swing line lender, and the other lenders party thereto, filed as Exhibit 10.1 to the Company s current report on Form 8-K (Commission File No. 001-32886) filed July 7, 2010 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 (15 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 (15 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).
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
** Furnished herewith