CONTINENTAL RESOURCES INC
Form 10-Q
November 05, 2010
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 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 incorporation or organization)	**(I.R.S. Employer Identification No.)**
302 N. Independence, Suite 1500, Enid, Oklahoma	**73701**
(Address of principal executive offices)	**(Zip Code)**

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant 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

170,042,442 shares of our $0.01 par value common stock were outstanding on November 1, 2010.

Table of Contents

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

Table of Contents

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. Exploratory or development well that does not produce crude oil and natural gas in economically producible quantities.

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.

Injection well. A well into which liquids or gases are injected in order to push additional crude oil or natural gas out of underground reservoirs and into the wellbores of producing wells. Typically considered an enhanced recovery process.

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

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

Mcfd. Mcf per day.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

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. The 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.

Table of Contents

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 results of operations;

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, 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.

Table of Contents

PART I. Financial Information

ITEM 1. Financial Statements

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Balance Sheets

In thousands, except par values and share data	September 30, 2010 (Unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 149,477	$ 14,222
Receivables:		
Oil and natural gas sales	162,299	119,565
Affiliated parties	11,885	7,823
Joint interest and other, net	202,144	55,970
Derivative assets	34,849	2,218
Inventories	31,056	26,711
Deferred and prepaid taxes	15	4,575
Prepaid expenses and other	6,295	4,944
Total current assets	598,020	236,028
Net property and equipment, based on successful efforts method of accounting	2,703,867	2,068,055
Debt issuance costs, net	28,076	10,844
Noncurrent derivative assets	4,662	
Total assets	$ 3,334,625	$ 2,314,927
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 313,348	$ 91,248
Revenues and royalties payable	95,505	66,789
Payables to affiliated parties	2,804	9,612
Accrued liabilities and other	112,888	49,601
Current portion of asset retirement obligations	2,761	2,460
Total current liabilities	527,306	219,710
Long-term debt	895,917	523,524
Other noncurrent liabilities:		
Deferred income tax liabilities	593,161	489,241
Asset retirement obligations, net of current portion	49,718	47,707
Noncurrent derivative liabilities	13,438	
Other noncurrent liabilities	6,334	4,466
Total other noncurrent liabilities	662,651	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		

Common stock, $0.01 par value; 500,000,000 shares authorized; 170,099,358 shares issued and outstanding at September 30, 2010; 169,968,471 shares issued and outstanding at December 31, 2009	1,701	1,700
Additional paid-in-capital	435,471	430,283
Retained earnings	811,579	598,296
Total shareholders equity	1,248,751	1,030,279
Total liabilities and shareholders equity	$ 3,334,625	$ 2,314,927

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

Table of Contents

Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Income

In thousands, except per share data	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010	Nine months ended September 30, 2009
Revenues:				
Oil and natural gas sales	$ 232,662	$ 162,465	$ 651,925	$ 389,310
Oil and natural gas sales to affiliates	6,164	5,907	23,451	18,069
Gain (loss) on mark-to-market derivative instruments	(24,183)	(2,105)	57,626	(1,215)
Oil and natural gas service operations	4,807	3,937	14,684	12,409
Total revenues	219,450	170,204	747,686	418,573
Operating costs and expenses:				
Production expenses	23,626	17,536	64,044	56,269
Production expenses to affiliates	1,231	5,183	5,762	12,914
Production taxes and other expenses	19,517	12,378	53,755	30,829
Exploration expenses	3,530	1,077	7,585	9,726
Oil and natural gas service operations	4,935	2,326	12,982	7,423
Depreciation, depletion, amortization and accretion	62,918	51,030	174,327	154,875
Property impairments	14,698	11,791	49,387	70,491
General and administrative expenses	12,148	10,049	35,491	29,684
(Gain) loss on sale of assets	491	(452)	(32,855)	(673)
Total operating costs and expenses	143,094	110,918	370,478	371,538
Income from operations	76,356	59,286	377,208	47,035
Other income (expense):				
Interest expense	(12,612)	(4,763)	(32,875)	(14,073)
Other	237	194	1,021	642
	(12,375)	(4,569)	(31,854)	(13,431)
Income before income taxes	63,981	54,717	345,354	33,604
Provision for income taxes	24,904	19,788	132,071	11,780
Net income	$ 39,077	$ 34,929	$ 213,283	$ 21,824
Basic net income per share	$ 0.23	$ 0.21	$ 1.26	$ 0.13
Diluted net income per share	$ 0.23	$ 0.21	$ 1.26	$ 0.13

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

Table of Contents

Continental Resources, Inc. and Subsidiary

Condensed Consolidated Statements of Shareholders Equity

In thousands, except share data	Shares outstanding	Common Stock	Additional paid-in Capital	Retained earnings	Total shareholders Equity
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)				213,283	213,283
Stock-based compensation (unaudited)			8,596		8,596
Stock options:					
Exercised (unaudited)	199,250	2	249		251
Repurchased and canceled (unaudited)	(57,397)	(1)	(2,540)		(2,541)
Restricted stock:					
Issued (unaudited)	60,667	1			1
Repurchased and canceled (unaudited)	(23,684)		(1,117)		(1,117)
Forfeited (unaudited)	(47,949)	(1)			(1)
Balance, September 30, 2010 (unaudited)	170,099,358	$ 1,701	$ 435,471	$ 811,579	$ 1,248,751

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

Table of Contents

Continental Resources, Inc. and Subsidiary

Unaudited Condensed Consolidated Statements of Cash Flows

In thousands	Nine months ended September 30, 2010	2009
Cash flows from operating activities:		
Net income	$ 213,283	$ 21,824
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	173,321	157,696
Property impairments	49,387	70,491
Change in fair value of derivatives	(28,162)	1,215
Stock-based compensation	8,596	8,594
Provision for deferred income taxes	116,165	11,780
Dry hole costs	1,943	5,002
Gain on sale of assets	(32,855)	(673)
Other, net	3,631	1,726
Changes in assets and liabilities:		
Accounts receivable	(192,970)	70,518
Inventories	(4,345)	(13,038)
Prepaid expenses and other	2,105	21,193
Accounts payable trade	99,869	(115,194)
Revenues and royalties payable	28,716	(22,465)
Accrued liabilities and other	54,008	(4,275)
Other noncurrent liabilities	2,648	1,601
Net cash provided by operating activities	495,340	215,995
Cash flows from investing activities:		
Exploration and development	(719,843)	(372,284)
Purchase of oil and natural gas properties	(7,319)	(1,217)
Purchase of other property and equipment	(20,453)	(4,682)
Proceeds from sale of assets	38,662	2,762
Net cash used in investing activities	(708,953)	(375,421)
Cash flows from financing activities:		
Revolving credit facility borrowings	289,000	372,100
Repayment of revolving credit facility	(515,000)	(502,500)
Proceeds from issuance of Senior Notes	587,210	297,480
Debt issuance costs	(8,932)	(9,826)
Repurchase of equity grants	(3,658)	(717)
Dividends to shareholders	(3)	(8)
Exercise of stock options	251	141
Other debt		2,822
Net cash provided by financing activities	348,868	159,492
Net change in cash and cash equivalents	135,255	66
Cash and cash equivalents at beginning of period	14,222	5,229
Cash and cash equivalents at end of period	$ 149,477	$ 5,295

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

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 in the North, South, and East regions of the United States. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Arkoma Woodford and Anadarko Woodford plays in Oklahoma. The East region contains properties east of the Mississippi river including the Illinois Basin and Michigan.

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 September 30, 2010 and for the three and nine month periods ended September 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 U.S. GAAP 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	**September 30, 2010**	**December 31, 2009**
Tubular goods and equipment	$ 18,038	$ 12,044
Crude oil	13,018	14,667

	$ 31,056	$ 26,711

Crude oil inventories consist of the following volumes:

In barrels	**September 30, 2010**	**December 31, 2009**
Crude oil line fill requirements	229,000	253,000
Temporarily stored crude oil	75,000	145,000
	304,000	398,000

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

Table of Contents

Earnings per common share

Basic earnings per common share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution of non-vested restricted stock awards and dilutive stock options, which are calculated using the treasury stock method as if these awards and options were exercised. The following is the calculation of basic and diluted weighted average shares outstanding and net income per share for the three and nine months ended September 30, 2010 and 2009:

In thousands, except per share data	Three months ended September 30, 2010	2009	Nine months ended September 30, 2010	2009
Income (numerator):				
Net income - basic and diluted	$ 39,077	$ 34,929	$ 213,283	$ 21,824
Weighted average shares (denominator):				
Weighted average shares - basic	168,925	168,516	168,889	168,492
Restricted shares	740	782	719	489
Employee stock options	284	408	296	418
Weighted average shares - diluted	169,949	169,706	169,904	169,399
Net income per share:				
Basic	$ 0.23	$ 0.21	$ 1.26	$ 0.13
Diluted	$ 0.23	$ 0.21	$ 1.26	$ 0.13

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. On the unaudited condensed consolidated statement of cash flows for the nine months ended September 30, 2009, the line item Gain on sale of assets was included in 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. Effective April 1, 2010, transactions with this entity are no longer reflected as affiliate transactions in the unaudited condensed consolidated financial statements. The balance sheet at December 31, 2009 includes $0.1 million from this party in Receivables Affiliated parties and $6.4 million in Payables to affiliated parties . Production expenses to affiliates includes $1.8 million in expenses from this party for the nine months ended September 30, 2010, all of which was recognized in the first quarter of the year, and $1.7 million and $6.4 million in expenses from this party for the three and nine months ended September 30, 2009, respectively.

Note 4. Supplemental Cash Flow Information

The following table discloses supplemental cash flow information about cash paid for interest and income taxes. Also disclosed is information about investing activities that affects recognized liabilities but does not result in cash receipts or payments.

In thousands	Nine months ended September 30, 2010	2009
Supplemental cash flow information:		
Cash paid for interest	$ 17,218	$ 13,675
Cash paid for income taxes	$ 10,876	$ 146

Cash received for income tax refunds	$	(1,288)	$	(22,018)
Non-cash investing activities				
Asset retirement obligations	$	1,325	$	555

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 consolidated statements of income under the caption Gain (loss) 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.

Table of Contents

During the nine months ended September 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, 2011, 2012 and 2013. 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.

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 , Accrued liabilities and other , and Noncurrent derivative liabilities . 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 September 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 Bbls	Weighted Average	Range	Weighted Average	Range	Weighted Average
October 2010 - December 2010						
Swaps	1,089,000	$ 83.99				
Collars	1,380,000		$ 75-$78	$ 76.00	$ 88.75-$96.75	$ 93.43
January 2011 - March 2011						
Swaps	284,000	83.86				
Collars	2,565,000		$ 75-$80	78.95	$ 88.65-$97.25	91.70
April 2011 - June 2011						
Swaps	91,000	81.22				
Collars	2,593,500		$ 75-$80	79.39	$ 89.00-$97.25	91.27
July 2011 - September 2011						
Swaps	92,000	81.22				
Collars	2,622,000		$ 75-$80	79.39	$ 89.00-$97.25	91.27
October 2011 - December 2011						
Swaps	92,000	81.22				
Collars	2,622,000		$ 75-$80	79.39	$ 89.00-$97.25	91.27
January 2012 - December 2012						
Swaps	1,830,000	84.57				
Collars	2,745,000		$ 80	80.00	$ 93.25-$93.65	93.54
January 2013 - December 2013						
Swaps	1,825,000	85.90				

Table of Contents

Natural Gas

Period and Type of Contract	MMBtu	Swaps Weighted Average
October 2010 - December 2010		
Swaps	3,778,000	$ 6.09
January 2011 - December 2011		
Swaps	11,862,500	6.36

Natural Gas Basis, Centerpoint East

Period and Type of Contract	MMBtu	Swaps Weighted Average
October 2010 - December 2010		
Basis swaps	1,800,000	$ (0.62)

Derivative Fair Value Gain (Loss)

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

In thousands	Three months ended September 30, 2010	2009	Nine months ended September 30, 2010	2009
Realized gain (loss) on derivatives:				
Crude oil fixed price swaps	$ 5,845	$	$ 13,275	$
Crude oil collars	825		1,884	
Natural gas fixed price swaps	6,373		16,628	
Natural gas basis swaps	(674)		(2,323)	
Unrealized gain (loss) on derivatives:				
Crude oil fixed price swaps	(17,538)		(6,727)	
Crude oil collars	(28,640)		6,445	
Natural gas fixed price swaps	9,258	(1,134)	26,552	701
Natural gas basis swaps	368	(971)	1,892	(1,916)
Gain (loss) on mark-to-market derivative instruments	$ (24,183)	$ (2,105)	$ 57,626	$ (1,215)

The table below provides data about the fair value of derivatives that are not accounted for using hedge accounting.

	September 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	$ 39,511	$ (13,438)	$ 26,073	$ 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 inputs 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 September 30, 2010. There were no transfers between Level 1 and Level 2 of the fair value hierarchy during the three and nine month periods ended September 30, 2010. Further, there were no transfers in and/or out of Level 3 of the fair value hierarchy during the three and nine month periods ended September 30, 2010.

In thousands	**Fair value measurements at September 30, 2010 using:**			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative assets (liabilities):				
Fixed price swaps	$	$ 23,606	$	$ 23,606
Basis swaps		(703)		(703)
Collars			3,170	3,170
Total	$	$ 22,903	$ 3,170	$ 26,073

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 periods:

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
Total realized or unrealized gains (losses):	
Included in earnings	(28,640)
Included in other comprehensive income	
Purchases, sales, issuances and settlements, net	
Transfers into Level 3	
Transfers out of Level 3	

Balance at September 30, 2010	$	3,170
Change in unrealized gains (losses) relating to derivatives still held at September 30, 2010	$	6,631

Gains and losses included in earnings for the three and nine month periods ended September 30, 2010 attributable to the change in unrealized gains and losses relating to derivatives held at September 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 to determine the fair value of proved properties. 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 proved crude oil and natural gas properties is calculated using significant unobservable inputs (Level 3).

Non-producing crude oil and natural gas properties, which primarily consist of undeveloped leasehold costs and costs associated with the purchase of proved undeveloped reserves, are assessed for impairment on a property-by-property basis for individually significant balances, if any, and on an aggregate basis by prospect for individually insignificant balances. If the assessment indicates an impairment, a loss is recognized by providing a valuation allowance at the level consistent with the level at which impairment was assessed. The impairment assessment is affected by economic factors such as the results of exploration activities, commodity price outlooks, remaining lease terms, and potential shifts in business strategy employed by management. For individually insignificant non-producing properties, the amount of the impairment loss recognized is determined by amortizing the portion of the properties costs which management believes will not be transferred to proved properties over the life of the lease based on experience of successful drilling and the average holding period. The fair value of non-producing properties is calculated using significant unobservable inputs (Level 3).

As a result of changes in reserves and the forward futures price strip, proved properties were reviewed for impairment at September 30, 2010. No impairment provisions were recorded for the Company s proved crude oil and natural gas properties for either the three months ended September 30, 2010 or 2009. For those periods, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary. Certain non-producing properties were impaired at September 30, 2010, reflecting amortization of leasehold costs. The following table sets forth the pre-tax (non-cash) impairments of both proved and non-producing properties for the indicated periods. Proved and non-producing property impairments are recorded under the caption Property impairments in the condensed consolidated statements of income.

In thousands	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010	Nine months ended September 30, 2009
Proved property impairments	$	$	$ 1,674	$ 36,051
Non-producing property impairments	14,698	11,791	47,713	34,440
Total	$ 14,698	$ 11,791	$ 49,387	$ 70,491

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 $0.6 million and $0.3 million for the three months ended September 30, 2010 and 2009, respectively, and was $1.4 million and $1.0 million for the nine months ended September 30, 2010 and 2009, respectively, which are 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).

Table of Contents

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.

	September 30, 2010		December 31, 2009	
In thousands	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt				
Revolving credit facility	$	$	$ 226,000	$ 226,000
8 1/4% Senior Notes due 2019 (1)	297,651	328,500	297,524	315,750
7 3/8% Senior Notes due 2020 (2)	198,266	210,750		
7 1/8% Senior Notes due 2021 (3)	400,000	415,000		
Total	$ 895,917	$ 954,250	$ 523,524	$ 541,750

(1) The carrying amount is net of discounts of $2.3 million and $2.5 million at September 30, 2010 and December 31, 2009, respectively.
(2) The carrying amount is net of discounts of $1.7 million at September 30, 2010.
(3) The notes were sold at par and are recorded at 100% of face value.

The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates available to the Company for bank loans with similar terms and maturities. The fair value of the 8 1/4% Senior Notes due 2019, the 7 3/8% Senior Notes due 2020 and the 7 1/8% Senior Notes due 2021 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 those instruments.

Note 7. Long-term Debt

Long-term debt consists of the following:

In thousands	**September 30, 2010**	**December 31, 2009**
Revolving credit facility	$	$ 226,000
8 1/4% Senior Notes due 2019 (1)	297,651	297,524
7 3/8% Senior Notes due 2020 (2)	198,266	
7 1/8% Senior Notes due 2021 (3)	400,000	
Total long-term debt	$ 895,917	$ 523,524

(1) The carrying amount is net of discounts of $2.3 million and $2.5 million at September 30, 2010 and December 31, 2009, respectively.
(2) The carrying amount is net of discounts of $1.7 million at September 30, 2010.
(3) The notes were sold at par and are recorded at 100% of face value.

Revolving credit facility

The Company had no debt outstanding at September 30, 2010 on its revolving credit facility due July 1, 2015. At December 31, 2009, the Company had $226.0 million in long-term debt outstanding on its revolving credit facility. The credit facility has aggregate commitments of $750 million and a borrowing base of $1.3 billion, subject to semi-annual redetermination. The terms of the facility provide that the commitment level can be increased up to the lesser of the borrowing base then in effect or $2.5 billion. Borrowings under the facility bear interest, payable quarterly, at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by the Company, plus a margin ranging from 175 to 275 basis points, depending on the percentage of its borrowing base utilized, or the lead bank s reference rate (prime). Borrowings are secured by our interest in at least 85% (by value) of all of the Company s proven reserves and associated crude oil and natural gas properties.

The Company had $747.7 million of unused commitments (after considering outstanding letters of credit) under the credit facility at September 30, 2010 and incurs commitment fees of 0.50% per annum of the daily average amount of unused borrowing availability. The credit facility contains certain restrictive covenants including a requirement that the Company maintain a current ratio of not less than 1.0 to 1.0 (representing current assets less current liabilities inclusive of available borrowing capacity under the credit agreement and exclusive of current balances associated with derivative contracts and asset retirement obligations) 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 September 30, 2010.

Senior Notes

8 1/4% Senior Notes due 2019 - On September 23, 2009, the Company issued $300 million of 8 1/4% Senior Notes due 2019 (the 2019 Notes) and 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 then outstanding under the revolving credit facility.

7 3/8% Senior Notes due 2020 - On April 5, 2010, the Company issued $200 million of 7 3/8% Senior Notes due 2020 (the 2020 Notes) and received net proceeds of approximately $194.2 million after deducting the initial purchasers discounts and fees. The 2020 Notes were sold in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended (the Securities Act), to qualified institutional buyers in reliance on Rule 144A of the Securities Act. The net proceeds were used to repay a portion of the borrowings then outstanding under the revolving credit facility.

15

7 ^{1}/8% Senior Notes due 2021 - On September 16, 2010, the Company issued $400 million of 7 1/8% Senior Notes due 2021 (the 2021 Notes). The 2021 Notes were sold at par in a transaction exempt from the registration requirements of the Securities Act to qualified institutional buyers in reliance on Rule 144A of the Securities Act. The Company received net proceeds of approximately $393.0 million after deducting the initial purchasers fees. The net proceeds were used to repay all borrowings outstanding under the revolving credit facility and to increase cash balances to fund a portion of the Company s 2010 capital program.

In connection with the issuance and sale of the 2020 Notes and the 2021 Notes, the Company entered into registration rights agreements (the Registration Rights Agreements) with the initial purchasers dated April 5, 2010 and September 16, 2010. Pursuant to the Registration Rights Agreements, the Company has agreed to file a registration statement with the SEC so that holders of the 2020 Notes and the 2021 Notes can exchange them for registered notes that have substantially identical terms as the 2020 Notes and the 2021 Notes. The Company has agreed to use reasonable efforts to cause the exchanges to be completed within 400 days after the issuance of the 2020 Notes and the 2021 Notes. The Company is required to pay additional interest if it fails to comply with its obligations to register the 2020 Notes and the 2021 Notes within the specified time period, whereby the interest rate 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 Agreements and complete the exchanges of the 2020 Notes and the 2021 Notes within the 400 day period.

The 2019 Notes, 2020 Notes, and 2021 notes (together, the Notes) will mature on October 1, 2019, October 1, 2020, and April 1, 2021, respectively. Interest on the Notes is payable semi-annually on April 1 and October 1 of each year, with interest on the 2021 Notes commencing on April 1, 2011. The Company has the option to redeem all or a portion of the 2019 Notes, 2020 Notes, and 2021 Notes at any time on or after October 1, 2014, October 1, 2015, and April 1, 2016, respectively, at the redemption prices specified in the Notes respective indentures (together, the Indentures) plus accrued and unpaid interest. The Company may also redeem the Notes, in whole or in part, at a make-whole redemption price specified in the Indentures plus accrued and unpaid interest at any time prior to October 1, 2014, October 1, 2015, and April 1, 2016 for the 2019 Notes, 2020 Notes, and 2021 Notes, respectively. In addition, the Company may redeem up to 35% of the 2019 Notes, 2020 Notes, and 2021 Notes prior to October 1, 2012, October 1, 2013, and April 1, 2014, respectively, under certain circumstances with the net cash proceeds from certain equity offerings.

The Indentures 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 Company was in compliance with these covenants as of September 30, 2010. The Notes are not subject to any mandatory redemption or 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 September 30, 2010, the Company had various drilling rig contracts with various terms extending through June 2012. These contracts were entered into in the normal course of business to ensure rig availability to allow the Company to execute its business objectives in its key strategic plays. These drilling commitments are not recorded in the accompanying consolidated balance sheets. Future drilling commitments as of September 30, 2010 are $3.1 million for contracts that expire in 2010, $45.8 million for contracts that expire in 2011 and $21.4 million for contracts that expire in 2012.

Fracturing and Well Stimulation Services Arrangement On August 20, 2010, the Company entered into an agreement with a third party to provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of the Company s properties in North Dakota and Montana. The arrangement has a term of three years, beginning in September 2010, with two one-year extensions available to the Company at its discretion. Pursuant to the take-or-pay arrangement, the Company is to pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether or not the services are provided. The arrangement also stipulates that the Company will bear the cost of certain products and materials used. Fixed commitments amount to $4.9 million per quarter, or $19.5 million annually, for total future commitments of $58.5 million over the three-year term. The commitments under this arrangement are not recorded in the accompanying consolidated balance sheets.

Employee retirement plan The Company maintains a defined contribution retirement plan for its employees and makes discretionary contributions to the plan based on a percentage of each eligible employee s compensation. During the nine months ended September 30, 2010 and the year ended December 31, 2009, contributions to the plan were 5% of eligible employees compensation, excluding bonuses. Expenses were $1.0 million and $0.9 million for the nine months ended September 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 September 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 September 30, 2010 and December 31, 2009, the Company has provided a reserve of $4.6 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.

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, which is included in the caption General and administrative expenses in the condensed consolidated statements of income, is reflected in the table below for the periods presented.

In thousands	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010	Nine months ended September 30, 2009
Non-cash equity compensation	$ 2,626	$ 3,172	$ 8,596	$ 8,594

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 September 30, 2010, options covering 2,200,723 shares had been exercised and 535,893 had been canceled.

The Company s stock option activity under the 2000 Plan for the nine months ended September 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	(199,250)	1.26	(199,250)	1.26
Outstanding at September 30, 2010	112,940	0.71	112,940	0.71

The intrinsic value of a stock option is the amount by which the value of the underlying stock exceeds the exercise price of the option at its exercise date. The total intrinsic value of options exercised during the nine months ended September 30, 2010 was approximately $8.5 million. At September 30, 2010, all options were exercisable and had a weighted average remaining life of 1.5 years with an aggregate intrinsic value of $5.2 million.

Restricted Stock

On October 3, 2005, the Company adopted the 2005 Plan and reserved a maximum of 5,500,000 shares of common stock that may be issued pursuant to the 2005 Plan. As of September 30, 2010, the Company had 3,302,152 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 generally vest over periods ranging from one to three years.

The Company began issuing shares of restricted common stock to employees and non-employee directors in October 2005. A summary of changes in the non-vested shares of restricted stock for the nine months ended September 30, 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	60,667	42.42
Vested	(92,273)	30.92
Forfeited	(47,949)	30.92
Non-vested restricted shares at September 30, 2010	1,047,266	26.88

The fair value of the restricted shares that vested during the nine months ended September 30, 2010 at their vesting date was $4.2 million. As of September 30, 2010, there was $12.5 million of unrecognized compensation expense related to non-vested restricted shares. The expense is expected to be recognized over a weighted average period of 1.0 year.

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. 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 production or revenues. The Company used the proceeds from the sale to fund a portion of its 2010 capital expenditures program.

Table of Contents

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 Part II, 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. The North region consists of properties north of Kansas and west of the Mississippi river and includes North Dakota Bakken, Montana Bakken, the Red River units and the Niobrara play in Colorado and Wyoming. The South region includes Kansas and all properties south of Kansas and west of the Mississippi river including the Arkoma Woodford and Anadarko Woodford plays in Oklahoma. The East region contains properties east of the Mississippi river including the Illinois Basin and Michigan.

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 revenues and operating income 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 nine months of 2010, our crude oil and natural gas production increased to 11,392 MBoe (41,728 Boe per day), up 1,241 MBoe, or 12%, from the first nine months of 2009. The increase in 2010 production was primarily driven by an increase in production from our North Dakota Bakken field and Oklahoma Woodford plays. Our crude oil and natural gas revenues for the first nine months of 2010 increased 66% to $675.4 million due to a 44% increase in commodity prices compared to the same period in 2009. Our realized price per Boe increased $17.90 to $58.82 for the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009. For the nine month period ended September 30, 2010, we experienced increases in production taxes and other expenses of $22.9 million, a 74% increase compared to the first nine months of 2009, primarily due to an increase in crude oil and natural gas revenues resulting from higher 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 nine months ended September 30, 2010, crude oil sales volumes were 90 MBbls more than crude oil production, and crude oil sales volumes were 196 MBbls less than crude oil production for the same period in 2009. Our cash flows from operating activities for the nine months ended September 30, 2010 were $495.3 million, an increase of $279.3 million from $216.0 million provided by our operating activities during the comparable 2009 period. The increase in operating cash flows was primarily due to increased revenues as a result of higher commodity prices and sales volumes. During the nine months ended September 30, 2010, we invested $866.1 million (including increased accruals for capital expenditures of $115.4 million and $3.1 million of seismic costs) in our capital program concentrating mainly in the Bakken field, the Arkoma Woodford 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 focuses primarily 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. In October 2010, our Board of Directors approved a 2011 capital expenditures budget of $1.36 billion, which will continue to focus primarily 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.

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.

Table of Contents

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

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Average daily production:				
Crude oil (Bopd)	33,432	27,552	31,404	27,265
Natural gas (Mcfd)	68,057	58,995	61,948	59,503
Crude oil equivalents (Boepd)	44,775	37,384	41,728	37,182
Average prices: (1)				
Crude oil ($/Bbl)	$ 67.26	$ 58.78	$ 68.92	$ 49.81
Natural gas ($/Mcf)	4.28	2.98	4.63	2.86
Crude oil equivalents ($/Boe)	56.92	48.19	58.82	40.92
Production expense ($/Boe) (1)	5.92	6.50	6.08	6.95
General and administrative expense ($/Boe) (1)	2.90	2.88	3.09	2.98
EBITDAX (in thousands) (2)	196,917	128,655	589,962	292,578
Net income (in thousands)	39,077	34,929	213,283	21,824
Diluted net income per share	0.23	0.21	1.26	0.13

(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 78 MBbls more than crude oil production for the three months ended September 30, 2010 and 55 MBbls more than crude oil production for the three months ended September 30, 2009. For the nine months ended September 30, 2010, crude oil sales volumes were 90 MBbls more than crude oil production and 196 MBbls less than crude oil production for the nine months ended September 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 September 30, 2010 compared to the three months ended September 30, 2009

Results of Operations

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

	Three months ended September 30,	
In thousands, except price data	2010	2009
Crude oil and natural gas sales	$ 238,826	$ 168,372
Gain (loss) on mark-to-market derivative instruments	(24,183)	(2,105)
Total revenues	219,450	170,204
Operating costs and expenses (1)	143,094	110,918
Other expenses, net	12,375	4,569
Income before income taxes	63,981	54,717
Provision for income taxes	24,904	19,788
Net income	$ 39,077	$ 34,929
Production Volumes:		

Crude oil (MBbl)	3,075	2,534
Natural gas (MMcf)	6,261	5,427
Crude oil equivalents (MBoe)	4,119	3,440
Sales Volumes:		
Crude oil (MBbl)	3,153	2,589
Natural gas (MMcf)	6,261	5,427
Crude oil equivalents (MBoe)	4,195	3,494
Average Prices: (2)		
Crude oil ($/Bbl)	$ 67.26	$ 58.78
Natural gas ($/Mcf)	$ 4.28	$ 2.98
Crude oil equivalents ($/Boe)	$ 56.92	$ 48.19

(1) Net of loss on sale of assets of $0.5 million and a gain on sale of assets of $0.5 million for the three months ended September 30, 2010 and 2009, respectively.

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

Table of Contents

Production

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

	Three months ended September 30, 2010		2009			
	Volume	Percent	Volume	Percent	Volume increase	Percent increase
Crude oil (MBbl)	3,075	75%	2,534	74%	541	21%
Natural Gas (MMcf)	6,261	25%	5,427	26%	834	15%
Total (MBoe)	4,119	100%	3,440	100%	679	20%

	Three months ended September 30, 2010		2009			
	MBoe	Percent	MBoe	Percent	Volume increase (decrease)	Percent increase (decrease)
North Region	3,230	78%	2,608	76%	622	24%
South Region	776	19%	696	20%	80	11%
East Region	113	3%	136	4%	(23)	(17)%
Total (MBoe)	4,119	100%	3,440	100%	679	20%

Crude oil production volumes increased 21% during the three months ended September 30, 2010 compared to the three months ended September 30, 2009. Production increases in the North Dakota Bakken field, Red River units, and the Oklahoma Woodford play contributed incremental volumes in 2010 of 659 MBbls in excess of production for the third quarter of 2009. Favorable results from drilling have been the primary contributors to production growth in these areas. Natural gas production volumes increased 834 MMcf, or 15%, during the three months ended September 30, 2010 compared to the same period in 2009. Natural gas production in the Bakken field in the North region was up 564 MMcf for the three months ended September 30, 2010 compared to the same period in 2009 due to additional natural gas being connected and sold in North Dakota. Natural gas production in the Oklahoma Woodford area increased 617 MMcf due to additional wells being completed and producing in the three months ended September 30, 2010 compared to the same period in 2009. These additional sales in the Bakken and Oklahoma Woodford plays were partially offset by decreases in natural gas volumes of 180 MMcf in the Cedar Hills field due to the conversion of producing wells to injection wells and 155 MMcf in the South region due to natural declines in a non-Woodford area.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the three months ended September 30, 2010 were $238.8 million, a 42% increase from sales of $168.4 million for the same period in 2009. Our sales volumes increased 701 MBoe, or 20%, 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 $8.73 to $56.92 for the three months ended September 30, 2010 from $48.19 for the three months ended September 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 September 30, 2010 was $8.93 compared to $9.39 for the three months ended September 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.

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 consolidated statements of income under the caption Gain (loss) on mark-to-market derivative instruments.

During the three months ended September 30, 2010, we realized gains on natural gas derivatives of $5.7 million and realized gains on crude oil derivatives of $6.7 million. During the three months ended September 30, 2010, we reported an unrealized non-cash mark-to-market gain on natural gas derivatives of $9.6 million and an unrealized non-cash mark-to-market loss on crude oil derivatives of $46.2 million. During the three months ended September 30, 2009, we had no derivative contracts related to our crude oil production and we reported unrealized non-cash mark-to-market losses from our natural gas derivatives of $2.1 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. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

Table of Contents

Reclaimed crude oil sales	Three months ended September 30, 2010	2009	Variance
Average sales price ($/Bbl)	$ 65.79	$ 56.90	$ 8.89
Sales volumes (barrels)	52,000	39,000	13,000

Prices for reclaimed crude oil sold from our central treating units were $8.89 per barrel higher for the three months ended September 30, 2010 than the comparable 2009 period, which contributed to an increase in reclaimed crude oil revenue by $0.7 million to $3.3 million, contributing to an overall increase in crude oil and natural gas service operations revenue of $0.9 million for the three months ended September 30, 2010. We sold high-pressure air from our Red River units to a third party and recorded revenues of $0.5 million for the three months ended September 30, 2009. Beginning in January 2010, we no longer sell high-pressure air to a third party. Associated crude oil and natural gas service operations expenses increased $2.6 million to $4.9 million during the three months ended September 30, 2010 from $2.3 million during the three months ended September 30, 2009 due mainly to an increase in the costs of purchasing and treating reclaimed 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 increased 9% to $24.9 million during the three months ended September 30, 2010 from $22.7 million during the three months ended September 30, 2009 due to higher production volumes. Production expense per Boe decreased to $5.92 for the three months ended September 30, 2010 from $6.50 per Boe for the three months ended September 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 resulting in the monthly lease fee being reduced to $50,000, lowering production expense per Boe for the 2010 period.

Production taxes and other expenses increased $7.1 million, or 58%, during the three months ended September 30, 2010 compared to the three months ended September 30, 2009 as a result of higher revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses include charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma Woodford area of $1.1 million and $1.5 million for the three months ended September 30, 2010 and 2009, respectively. Production taxes, excluding other charges, as a percentage of crude oil and natural gas sales, were 7.7% for the three months ended September 30, 2010 compared to 6.7% for the three months ended September 30, 2009. The increase is due to the expiration of various tax incentives coupled with higher taxable revenues in North Dakota, our most active area, which has production tax rates of up to 11.5% of oil revenues. 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:

$/Boe	Three months ended September 30, 2010	2009	Percent increase (decrease)
Production expenses	$ 5.92	$ 6.50	(9)%
Production taxes and other expenses	4.65	3.54	31%
Production expenses, production taxes and other expenses	$ 10.57	$ 10.04	5%

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $2.5 million in the three months ended September 30, 2010 to $3.5 million due primarily to increases in seismic expense of $0.9 million and dry hole expense of $1.5 million.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $11.9 million, or 23%, in the third quarter of 2010 compared to the third quarter of 2009, primarily due to the increase in production. The following table shows the components of our DD&A rate per Boe.

$/Boe	Three months ended September 30, 2010	2009
Crude oil and natural gas	$ 14.59	$ 14.22
Other equipment	0.24	0.22
Asset retirement obligation accretion	0.16	0.16
Depreciation, depletion, amortization and accretion	$ 14.99	$ 14.60

Property Impairments. Property impairments, which consisted entirely of impairments of non-producing properties for the three months ended September 30, 2010 and 2009, increased $2.9 million during the three months ended September 30, 2010 to $14.7 million compared to $11.8 million for the three months ended September 30, 2009 reflecting amortization of leasehold costs. 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.

We did not record any impairment provisions for proved oil and gas properties for either the three months ended September 30, 2010 or 2009. We evaluate our proved 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. For both the three months ended September 30, 2010 and 2009, future cash flows were determined to be in excess of cost basis and no impairment was necessary.

General and Administrative Expenses. General and administrative expenses increased $2.1 million to $12.1 million during the three months ended September 30, 2010 from $10.0 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 $2.6 million and $3.2 million for the three months ended September 30, 2010 and 2009, respectively. General and administrative expenses excluding stock-based compensation increased $2.7 million for the three months ended September 30, 2010 compared to the same period in 2009. On a volumetric basis, general and administrative expenses increased $0.02 to $2.90 per Boe for the three months ended September 30, 2010 compared to $2.88 per Boe for the three months ended September 30, 2009.

Interest Expense. Interest expense increased 165%, or $7.8 million, for the three months ended September 30, 2010 compared to the three months ended September 30, 2009, due to an increase in our outstanding debt balance in the current year coupled with higher rates of interest being incurred on our senior notes in the current year compared to interest rates on our credit facility borrowings in the prior year. On September 23, 2009, we issued $300 million of 8 1/4% Senior Notes due 2019. On April 5, 2010, we issued $200 million of 7 3/8% Senior Notes due 2020. On September 16, 2010, we issued $400 million of 7 1/8% Senior Notes due 2021. We recorded $10.3 million in interest expense on the outstanding senior notes for the three months ended September 30, 2010. Including the interest on the senior notes, our weighted average interest rate for the three months ended September 30, 2010 was 6.2% with a weighted average outstanding balance of $730.8 million, while for the three months ended September 30, 2009 our weighted average rate was 2.82% with a weighted average outstanding balance of $581.6 million.

Our average revolving credit facility balance decreased to $170.0 million for the three months ended September 30, 2010 compared to $558.8 million for the three months ended September 30, 2009. The weighted average interest rate on our revolving credit facility borrowings was higher at 2.66% for the three months ended September 30, 2010 compared to 2.59% for the same period in 2009. At September 30, 2010, we had no outstanding borrowings on our revolving credit facility.

Income Taxes. We recorded income tax expense for the three months ended September 30, 2010 of $24.9 million compared to $19.8 million for the three months ended September 30, 2009. We provide for income taxes at a combined federal and state tax rate of approximately 38% after taking into account permanent taxable differences.

Table of Contents

Nine months ended September 30, 2010 compared to the nine months ended September 30, 2009

Results of Operations

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

In thousands, except price data	Nine months ended September 30, 2010	2009
Crude oil and natural gas sales	$ 675,376	$ 407,379
Gain (loss) on mark-to-market derivative instruments	57,626	(1,215)
Total revenues	747,686	418,573
Operating costs and expenses [(1)]	370,478	371,538
Other expenses, net	31,854	13,431
Income before income taxes	345,354	33,604
Provision for income taxes	132,071	11,780
Net income	$ 213,283	$ 21,824
Production Volumes:		
Crude oil (MBbl)	8,573	7,443
Natural gas (MMcf)	16,912	16,244
Crude oil equivalents (MBoe)	11,392	10,151
Sales Volumes:		
Crude oil (MBbl)	8,663	7,247
Natural gas (MMcf)	16,912	16,244
Crude oil equivalents (MBoe)	11,481	9,955
Average Prices: [(2)]		
Crude oil ($/Bbl)	$ 68.92	$ 49.81
Natural gas ($/Mcf)	$ 4.63	$ 2.86
Crude oil equivalents ($/Boe)	$ 58.82	$ 40.92

(1) Net of gain on sale of assets of $32.9 million and $0.7 million for the nine months ended September 30, 2010 and 2009, respectively. 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. 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 production or revenues.

(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.

	Nine months ended September 30, 2010		2009			
	Volume	Percent	Volume	Percent	Volume increase	Percent increase
Crude oil (MBbl)	8,573	75%	7,443	73%	1,130	15%
Natural Gas (MMcf)	16,912	25%	16,244	27%	668	4%
Total (MBoe)	11,392	100%	10,151	100%	1,241	12%

	Nine months ended September 30, 2010		2009		Volume increase	Percent increase
	MBoe	Percent	MBoe	Percent	(decrease)	(decrease)
North Region	8,969	79%	7,634	75%	1,335	17%
South Region	2,078	18%	2,127	21%	(49)	(2)%
East Region	345	3%	390	4%	(45)	(12)%
Total (MBoe)	11,392	100%	10,151	100%	1,241	12%

Crude oil production volumes increased 15% during the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009. Production increases in the North Dakota Bakken field, Cedar Hills field and the Oklahoma Woodford play contributed incremental volumes in 2010 of 1,625 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 324 MBbls due to wells shut in for repairs and natural declines. Natural gas volumes increased 668 MMcf, or 4%, during the nine months ended September 30, 2010 compared to the same period in 2009. Natural gas production in the Bakken field in the North region was up 1,742 MMcf for the nine months ended September 30, 2010 compared to the same period in 2009 due to additional natural gas being connected and sold in North Dakota. Natural gas production in the Oklahoma Woodford area increased 550 MMcf due to additional wells being completed and producing in the nine months ended September 30, 2010 compared to the same period in 2009. These additional sales in the Bakken and Oklahoma Woodford plays were partially offset by a decrease in natural gas volumes of 731 MMcf in the Red River units due to the conversion of producing wells to injection wells and the Badlands plant being down for repairs. Further, other South region natural gas volumes decreased 880 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 nine months ended September 30, 2010 were $675.4 million, a 66% increase from sales of $407.4 million for the same period in 2009. Our sales volumes increased 1,526 MBoe, or 15%, 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 $17.90 to $58.82 for the nine months ended September 30, 2010 from $40.92 for the nine months ended September 30, 2009. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the nine months ended September 30, 2010 was $8.68 compared to $7.91 for the nine months ended September 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.

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 consolidated statements of income under the caption Gain (loss) on mark-to-market derivative instruments.

During the nine months ended September 30, 2010, we realized gains on natural gas derivatives of $14.3 million and realized gains on crude oil derivatives of $15.2 million. During the nine months ended September 30, 2010, we reported an unrealized non-cash mark-to-market gain on natural gas derivatives of $28.4 million and an unrealized non-cash mark-to-market loss on crude oil derivatives of $0.3 million. During the nine months ended September 30, 2009, we had no derivative contracts related to our crude oil production and we reported unrealized non-cash mark-to-market losses from our natural gas derivatives of $1.2 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. The table below shows the volumes and prices for the sale of reclaimed crude oil for the periods presented.

	Nine months ended September 30,		
Reclaimed crude oil sales	**2010**	**2009**	**Variance**
Average sales price ($/Bbl)	$ 67.46	$ 43.61	$ 23.85
Sales volumes (barrels)	167,000	156,000	11,000

Prices for reclaimed crude oil sold from our central treating units were $23.85 per barrel higher for the nine months ended September 30, 2010 than the comparable 2009 period, which contributed to an increase in reclaimed crude oil revenue by $4.1 million to $12.0 million, contributing to an overall increase in crude oil and natural gas service operations revenue of $2.3 million for the nine months ended September 30, 2010. We sold high-pressure air from our Red River units to a third party and recorded revenues of $1.6 million for the nine months ended September 30, 2009. Beginning in January 2010, we no longer sell high-pressure air to a third party. Associated crude oil and natural gas service operations expenses increased $5.6 million to $13.0 million during the nine months ended September 30, 2010 from $7.4 million during the nine months ended September 30, 2009 due mainly to an increase in the costs of purchasing and treating reclaimed 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 increased 1% to $69.8 million during the nine months ended September 30, 2010 from $69.2 million during the nine months ended September 30, 2009 due to higher production volumes. Production expense per Boe decreased to $6.08 for the nine months ended September 30, 2010 from $6.95 per Boe for the nine months ended September 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 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 interpretations.

Production taxes and other expenses increased $22.9 million, or 74%, during the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009 as a result of higher revenues resulting from increased commodity prices and sales volumes along with the expiration of various tax incentives. Production taxes and other expenses include charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Arkoma Woodford area of $4.4 million and $5.4 million for the nine months ended September 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 nine months ended September 30, 2010 compared to 6.4% for the nine months ended September 30, 2009. The increase is due to the expiration of various tax incentives coupled with higher taxable revenues in North Dakota, our most active area, which has production tax rates of up to 11.5% of oil revenues. 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.

Table of Contents

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

$/Boe	Nine months ended September 30, 2010	2009	Percent increase (decrease)
Production expenses	$ 6.08	$ 6.95	(13)%
Production taxes and other expenses	4.68	3.10	51%
Production expenses, production taxes and other expenses	$ 10.76	$ 10.05	7%

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses decreased $2.1 million in the nine months ended September 30, 2010 to $7.6 million due primarily to a decrease in dry hole expense of $3.1 million, partially offset by a $1.6 million increase in seismic expenses.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $19.5 million, or 13%, in the first nine 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.

$/Boe	Nine months ended September 30, 2010	2009
Crude oil and natural gas	$ 14.78	$ 15.16
Other equipment	0.24	0.23
Asset retirement obligation accretion	0.17	0.17
Depreciation, depletion, amortization and accretion	$ 15.19	$ 15.56

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.

Property Impairments. Property impairments, both proved and non-producing, decreased in the nine months ended September 30, 2010 by $21.1 million to $49.4 million compared to $70.5 million during the nine months ended September 30, 2009.

Impairment of non-producing properties increased $13.3 million during the nine months ended September 30, 2010 to $47.7 million compared to $34.4 million for the nine months ended September 30, 2009 reflecting amortization of leasehold costs. 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 proved crude oil and natural gas properties were approximately $1.7 million for the nine months ended September 30, 2010 compared to approximately $36.1 million for the nine months ended September 30, 2009, a decrease of $34.4 million, or 95%. We evaluate our proved 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 proved 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 nine months ended September 30, 2010. Impairments of proved properties in 2009 reflect uneconomic drilling results in the first half of 2009 in our South region, which resulted in impairments of $24.1 million. The remaining 2009 impairments were the result of decreases in reserves and prices.

General and Administrative Expenses. General and administrative expenses increased $5.8 million to $35.5 million during the nine months ended September 30, 2010 from $29.7 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 $8.6 million for both the nine months ended September 30, 2010 and 2009. On a volumetric basis, general and administrative expenses increased $0.11 to $3.09 per Boe for the nine months ended September 30, 2010 compared to $2.98 per Boe for the nine months ended September 30, 2009.

Interest Expense. Interest expense increased 134%, or $18.8 million, for the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009, due to an increase in our outstanding debt balance in the current year coupled with higher rates of interest being incurred on our senior notes in the current year compared to interest rates on our credit facility borrowings in the prior year. On September 23, 2009, we issued $300 million of $8\,^{1}/_{4}$% Senior Notes due 2019. On April 5, 2010, we issued $200 million of $7\,^{3}/_{8}$% Senior Notes due 2020. On September 16, 2010, we issued $400 million of $7\,^{1}/_{8}$% Senior Notes due 2021. We recorded $26.6 million in interest expense on the outstanding senior notes for the nine months ended September 30, 2010. Including the interest on the senior notes, our weighted average interest rate for the nine months ended September 30, 2010 was 6.64% with a weighted average outstanding balance of $612.1 million compared to a weighted average interest rate of 2.98% and a weighted average outstanding balance of $558.8 million for the nine months ended September 30, 2009.

Our average revolving credit facility balance decreased to $161.2 million for the nine months ended September 30, 2010 compared to $550.7 million for the nine months ended September 30, 2009. The weighted average interest rate on our revolving credit facility borrowings was lower at 2.66% for the nine months ended September 30, 2010 compared to 2.90% for the same period in 2009. At September 30, 2010, we had no outstanding borrowings on our revolving credit facility.

Income Taxes. We recorded income tax expense for the nine months ended September 30, 2010 of $132.1 million compared to $11.8 million for the nine months ended September 30, 2009. We provide for income 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 senior notes. During the first nine months of 2010, our crude oil prices were $19.11 per barrel higher than the first nine months of 2009, and we have seen our natural gas prices for the first nine months of 2010 increase 62% compared to the first nine months of 2009. The increased prices of crude oil and natural gas in the current year resulted in improved cash flows from operations and better liquidity.

At September 30, 2010, we had approximately $149.5 million of cash and cash equivalents and approximately $747.7 million (after considering outstanding letters of credit) of net available liquidity under our revolving credit facility.

Cash Flows

Cash Flows from Operating Activities

Our net cash provided by operating activities was $495.3 million and $216.0 million for the nine months ended September 30, 2010 and 2009, respectively. The increase in operating cash flows was primarily due to higher revenues as a result of higher commodity prices and sales volumes in the current period.

Cash Flows from Investing Activities

During the nine months ended September 30, 2010 and 2009, we had cash flows used in investing activities (excluding asset sales) of $747.6 million and $378.2 million, respectively, related to our capital program, inclusive of dry hole costs. The increase in our cash flows used in investing activities was due to the current year 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 nine months ended September 30, 2010 was $348.9 million and was mainly the result of the issuance of the $200 million of 2020 Notes in April 2010 and the issuance of the $400 million of 2021 Notes in September 2010 along with borrowings on our credit facility, partially offset by amounts repaid under our credit facility. Net cash provided by financing activities of $159.5 million for the nine months ended September 30, 2009 was mainly the result of amounts received from the issuance of the $300 million of 2019 Notes in September 2009 along with borrowings on our credit facility, partially offset by amounts repaid under our credit facility.

Future Sources of Financing

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.

Based on our planned production growth and the existence of derivative contracts in place to limit the downside risk of adverse price movements associated with the forecasted sale of future production, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our short-term and 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, but may also include 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.

Revolving Credit Facility

On June 30, 2010, we entered into an amended and restated revolving 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 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 million commitment.

We had no outstanding borrowings under our credit facility at September 30, 2010 and $226.0 million outstanding at December 31, 2009. As of September 30, 2010, we had $747.7 million of borrowing availability under our credit facility (after considering outstanding letters of credit). On September 16, 2010, we issued $400 million of the 2021 Notes and received net proceeds of approximately $393.0 million after deducting initial purchasers fees. The net proceeds were used to repay all borrowings outstanding under our credit facility, which had a balance prior to payoff of $182 million. Prior to payoff, weighted average outstanding borrowings under our credit facility amounted to $170.0 million during the third quarter of 2010. As of November 1, 2010, we continue to have no outstanding borrowings and $747.7 million of borrowing availability under our credit facility.

In the future, we may not be able to access adequate funding under our 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. We expect the next borrowing base redetermination to occur in the fourth quarter of 2010. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base.

Our credit agreement contains certain restrictive covenants including a requirement that we maintain a current ratio of not less than 1.0 to 1.0 (representing current assets less current liabilities inclusive of available borrowing capacity under the credit agreement and exclusive of current balances associated with derivative contracts and asset retirement obligations) and a ratio of total funded debt to EBITDAX of no greater than 3.75 to 1.0. We were in compliance with all covenants at September 30, 2010 and we expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants will materially limit our ability to undertake additional debt or equity financing.

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.

Issuances of Long-Term Debt

On September 23, 2009, we issued $300 million of 8 1/4% Senior Notes due 2019 and received net proceeds of approximately $289.7 million after deducting the initial purchasers discounts and fees. On April 5, 2010, we issued $200 million of 7 3/8% Senior Notes due 2020 and received net proceeds of approximately $194.2 million after deducting the initial purchasers discounts and fees. The net proceeds from these offerings were used to repay a portion of the borrowings then outstanding under our revolving credit facility that were incurred to fund capital expenditures. On September 16, 2010, we issued $400 million of 7 1/8% Senior Notes due 2021 and received net proceeds of approximately $393.0 million after deducting initial purchasers fees. The net proceeds were used to repay the remaining borrowings outstanding under the revolving credit facility that were incurred to fund capital expenditures and to increase cash balances to fund a portion of our 2010 capital program.

The 2019 Notes, 2020 Notes, and 2021 Notes (together, the Notes) will mature on October 1, 2019, October 1, 2020, and April 1, 2021, respectively. Interest on the Notes is payable semi-annually on April 1 and October 1 of each year, with interest on the 2021 Notes commencing on April 1, 2011. We have the option to redeem all or a portion of the 2019 Notes, 2020 Notes, and 2021 Notes at any time on or after October 1, 2014, October 1, 2015, and April 1, 2016, respectively, at the redemption prices specified in the Notes respective indentures (together, the Indentures) plus accrued and unpaid interest. We may also redeem the Notes, in whole or in part, at a make-whole redemption price specified in the Indentures, plus accrued and unpaid interest, at any time prior to October 1, 2014, October 1, 2015, and April 1, 2016 for the 2019 Notes, 2020 Notes, and 2021 Notes, respectively. In addition, we may redeem up to 35% of the 2019 Notes, 2020 Notes, and 2021 Notes prior to October 1, 2012, October 1, 2013, and April 1, 2014, respectively, under certain circumstances with the net cash proceeds from certain equity offerings. Currently, we have no plans or intentions of exercising an early redemption option on the Notes. The Notes are not subject to any mandatory redemption or sinking fund requirements.

The Indentures contain certain restrictions on our ability to incur additional debt, pay dividends on our 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 our assets. These covenants are subject to a number of important exceptions and qualifications. We were in compliance with these covenants as of September 30, 2010 and expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants will materially limit our ability to undertake additional debt or equity financing. Our subsidiary, which currently has no independent assets or operations, fully and unconditionally guarantees the Notes.

Registration Statement Filing

On July 16, 2010, we filed a shelf registration statement on Form S-3 pursuant to which we may offer from time to time one or more series of debt or equity securities. We may issue additional long-term debt and equity securities from time to time when market conditions are favorable and when the need arises. The nature, amounts, terms, and timing of such financing arrangements, and the related impact on our financial position, results of operations, and liquidity are currently indeterminable. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Derivative Activities

As part of our risk management program, we hedge a portion of our anticipated future crude oil and natural gas production for the next 12-42 months to achieve more predictable cash flows and to reduce our exposure to fluctuations in crude oil and natural gas prices. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital program. While the use of these hedging arrangements limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. Our derivative contracts are with multiple counterparties to minimize our exposure to credit risk with any individual counterparty.

During the nine months ended September 30, 2010, we realized gains on crude oil and natural gas derivatives of $29.4 million and reported an unrealized non-cash mark-to-market gain on derivatives of $28.2 million. The fair value of our derivative instruments at September 30, 2010 was a net asset of $26.1 million.

Future Capital Requirements

Capital Expenditures

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 nine months of 2010, we participated in the completion of 233 gross (80.2 net) wells and invested a total of $866.1 million (including increases in accruals for capital expenditures of $115.4 million and $3.1 million of seismic costs) in our capital program as shown in the following table.

in millions	**Amount**
Exploration and development drilling	$ 519.5
Land costs	291.2
Capital facilities, workovers and re-completions	22.6
Vehicles, computers and other equipment	20.5
Acquisition of producing properties	7.3
Seismic	3.1
Dry holes	1.9

Total	$ 866.1

The revised 2010 capital expenditures budget of $1.3 billion primarily focuses 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.

29

Table of Contents

In October 2010, our Board of Directors approved a 2011 capital expenditures budget of $1.36 billion. Our 2011 planned capital expenditures are expected to be allocated as follows:

in millions	**Amount**
Exploration and development drilling	$ 1,135
Land costs	117
Capital facilities, workovers and re-completions	92
Seismic	15
Vehicles, computers and other equipment	5
Total	$ 1,364

The 2011 capital expenditures budget of $1.36 billion will continue to focus primarily 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 available borrowing capacity under our revolving credit facility will be sufficient to fund our 2010 and 2011 capital budgets. 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.

Commitments

As of September 30, 2010, we had various drilling rig contracts with various terms extending through June 2012. These contracts were entered into in the normal course of business to ensure rig availability to allow us to execute our business objectives in our key strategic plays. These drilling commitments are not recorded in the accompanying consolidated balance sheets. Future drilling commitments as of September 30, 2010 are $3.1 million for contracts that expire in 2010, $45.8 million for contracts that expire in 2011 and $21.4 million for contracts that expire in 2012.

On August 20, 2010, we entered into an agreement with a third party to provide, on a take-or-pay basis, hydraulic fracturing services and related equipment to service certain of our properties in North Dakota and Montana. The arrangement has a term of three years, beginning in September 2010, with two one-year extensions available to us at our discretion. Pursuant to the take-or-pay arrangement, we will pay a fixed rate per day for a minimum number of days per calendar quarter over the three-year term regardless of whether or not the services are provided. Fixed commitments amount to $4.9 million per quarter, or $19.5 million annually, for total future commitments of $58.5 million over the three-year term. The commitments under this arrangement are not recorded in the accompanying consolidated balance sheets.

We believe that our cash flows from operations and available borrowing capacity under our revolving credit facility will be sufficient to satisfy the above commitments.

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 our operations from period to period without regard to our 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 our 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 U.S. 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 September 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.

in thousands	Three months ended September 30, 2010	2009	Nine months ended September 30, 2010	2009
Net income	$ 39,077	$ 34,929	$ 213,283	$ 21,824
Interest expense	12,612	4,763	32,875	14,073
Provision for income taxes	24,904	19,788	132,071	11,780
Depreciation, depletion, amortization and accretion	62,918	51,030	174,327	154,875
Property impairments	14,698	11,791	49,387	70,491
Exploration expenses	3,530	1,077	7,585	9,726
Unrealized derivative (gain) loss	36,552	2,105	(28,162)	1,215
Non-cash equity compensation	2,626	3,172	8,596	8,594
EBITDAX	$ 196,917	$ 128,655	$ 589,962	$ 292,578

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

General

We are exposed to a variety of market risks including commodity price risk, credit 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 nine months ended September 30, 2010, our annual revenue would increase or decrease by approximately $114.6 million for each $10.00 per barrel change in crude oil prices and $22.6 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 nine months ended September 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, 2011, 2012 and 2013. 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 *Note 5 Derivative Contracts* in *Notes to Unaudited Condensed Consolidated Financial Statement*s for additional information regarding our swap and collar derivative contracts.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, which, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and the entities that participate in that market. Significant regulations are required to be promulgated by the SEC and the Commodity Futures Trading Commission within 360 days from the date of enactment to implement the new legislation. The new legislation, to the extent applicable to us or our derivative counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in commodity prices, and could have an adverse effect on our ability to hedge risks associated with our business. Many of the key concepts and processes under the Dodd-Frank Act are not defined and must be delineated by rules and regulations to be adopted by the applicable regulatory agencies. As a consequence, it is not possible at this time to predict the effects that the Dodd-Frank Act or the resulting rules and regulations may have on our hedging activities.

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 ($166.3 million in receivables at September 30, 2010), our joint interest receivables ($210.0 million at September 30, 2010), and counterparty credit risk associated with our derivative instruments.

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. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.

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. This liability was $54.8 million and $13.5 million at September 30, 2010 and December 31, 2009, respectively, which will be used to offset future capital costs when billed. 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.

Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty. Currently, all of our derivative contracts are with parties that are lenders under our revolving credit agreement.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to borrowings outstanding under our revolving credit facility. We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-rate debt. 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 may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives. We are exposed to changes in interest rates as a result of our credit facility. We had no revolving credit facility debt outstanding under our revolving credit facility at November 1, 2010.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Based on management s evaluation, under the supervision and with the participation of our principal executive officer and principal financial officer, as of the end of the period covered by this report, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures (which are defined in rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) were effective as of September 30, 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 September 30, 2010, we implemented a new Company-wide enterprise resource planning software system, SAP, to replace our previous system. The new SAP system became operational on July 1, 2010. The system implementation was undertaken to enhance our accounting and reporting procedures, provide more standardized and efficient business processes, and provide flexibility to adapt to the planned future growth of our Company. In conjunction with the SAP implementation, the Company modified the design, operation and documentation of its internal controls over financial reporting in the business processes impacted by the new system. Management believes these changes will maintain and strengthen our overall internal controls.

Except as described above, there were no other 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 occurred during our most recent fiscal quarter 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.

Table of Contents

PART II. Other Information

ITEM 1. Legal Proceedings

From time to time, we are a party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business. We are 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

Except as set forth below, 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 that was filed with the SEC on February 26, 2010.

In addition to the 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.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price risk and other risks associated with our business.

We use derivative instruments to manage our commodity price risk. The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by President Obama on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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.

Table of Contents

The following table provides information about purchases of equity securities that are registered by us pursuant to Section 12 of the Exchange Act during the quarter ended September 30, 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)
July 1, 2010 to July 31, 2010	750	$ 43.57		
August 1, 2010 to August 31, 2010	2,023	$ 47.62		
September 1, 2010 to September 30, 2010	57,397	$ 44.26		
Total	60,170	$ 44.36		

(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. 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.

Table of Contents

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.

Table of Contents

SIGNATURE

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

Continental Resources, Inc.

Date: November 5, 2010

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

(Duly Authorized Officer and Principal Financial Officer)

Index to Exhibits

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 September 16, 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 September 17, 2010 and incorporated herein by reference.
4.2	Registration Rights Agreement dated as of September 16, 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 September 17, 2010 and incorporated herein by reference.
10.1	Purchase Agreement dated as of September 13, 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 September 14, 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