CONTINENTAL RESOURCES, INC
Form 10-Q
May 08, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2013

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.)**
20 N. Broadway, Oklahoma City, Oklahoma	**73102**
(Address of principal executive offices)	**(Zip Code)**

(405) 234-9000

(Registrant s telephone number, including area code)

Not Applicable

(Former name, former address and former fiscal year, if changed since last report)

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

185,627,255 shares of our $0.01 par value common stock were outstanding on April 30, 2013.

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

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Glossary of Crude Oil and Natural Gas Terms

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

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

Boe Barrels of crude oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of crude oil based on the average equivalent energy content of the two commodities.

Btu British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

completion The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil and/or natural gas.

conventional play An area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

DD&A Depreciation, depletion, amortization and accretion.

developed acreage The number of acres allocated or assignable to productive wells or wells capable of production.

development well A well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

dry gas Refers to natural gas that remains in a gaseous state in the reservoir and does not produce large quantities of liquid hydrocarbons when brought to the surface. Also may refer to gas that has been processed or treated to remove all natural gas liquids.

dry hole Exploratory or development well that does not produce crude oil and/or 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, supplementing its natural energy. Enhanced recovery methods are sometimes applied when production slows due to depletion of the natural pressure.

exploratory well A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir.

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

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

horizontal drilling A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

hydraulic fracturing A process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production.

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.

MMBoe One million Boe.

MMBtu One million British thermal units.

MMcf One million cubic feet of natural gas.

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net acres The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has a 50% interest in 100 acres owns 50 net acres.

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.

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

prospect A potential geological feature or formation which geologists and geophysicists believe may contain hydrocarbons. A prospect can be in various stages of evaluation, ranging from a prospect that has been fully evaluated and is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

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 renewal is reasonably certain.

proved developed reserves Reserves expected to be recovered through existing wells with existing equipment and operating methods.

proved undeveloped reserves or *PUD* Proved reserves 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.

resource play Refers to an expansive contiguous geographical area with prospective crude oil and/or natural gas reserves that has the potential to be developed uniformly with repeatable commercial success due to advancements in horizontal drilling and multi-stage fracturing technologies.

royalty interest Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

SCOOP Refers to the South Central Oklahoma Oil Province, a term we use to describe an emerging area of crude oil and liquids-rich natural gas properties located in the Anadarko basin of south central Oklahoma.

unconventional play An area believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as is the case with oil and gas shale, tight oil and gas sands and coalbed methane.

undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

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.

working interest The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

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Cautionary Statement for the Purpose of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact, including, but not limited to, statements or information concerning the Company s future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, returns, budgets, costs, business strategy, objectives, and cash flow, included in this report are forward-looking statements. When used in this report, the words could, may, believe, anticipate, intend, estimate, expect, project, budget, plan, continue, potential, gu similar expressions are intended to identify 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 currently available information as to the outcome and timing of future events. Although the Company believes the expectations reflected in the forward-looking statements are reasonable and based on reasonable assumptions, no assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under *Part II, Item 1A. Risk Factors* included in this report, our Annual Report on Form 10-K for the year ended December 31, 2012, registration statements filed from time to time with the SEC, and other announcements we make from time to time.

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;
- our future operations;
- our reserves;
- our technology;
- our financial strategy;
- crude oil, natural gas liquids, and natural gas prices and differentials;
- the timing and amount of future production of crude oil and natural gas and flaring activities;
- the amount, nature and timing of capital expenditures;
- estimated revenues, expenses and results of operations;
- drilling and completing of wells;

competition;

marketing of crude oil and natural gas;

transportation of crude oil, natural gas liquids, and natural gas to markets;

exploitation or property acquisitions and dispositions;

costs of exploiting and developing our properties and conducting other operations;

our financial position;

general economic conditions;

credit markets;

our liquidity and access to capital;

the impact of governmental policies, laws and regulations, as well as regulatory and legal proceedings involving us and of scheduled or potential regulatory or legal changes;

our future operating results;

plans, objectives, expectations and intentions contained in this report that are not historical, including, without limitation, statements regarding our future growth plans;

our commodity hedging arrangements; and

the ability and willingness of current or potential lenders, hedging contract counterparties, customers, and working interest owners to fulfill their obligations to us or to enter into transactions with us in the future on terms that are acceptable to us.

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We caution you 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, completion 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 *Part II, Item 1A. Risk Factors* in this report, our Annual Report on Form 10-K for the year ended December 31, 2012, 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 to reflect events or circumstances after the date of this report.

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PART I. Financial Information

ITEM 1. Financial Statements

Continental Resources, Inc. and Subsidiaries

Condensed Consolidated Balance Sheets

	March 31, 2013 *(Unaudited)*	December 31, 2012
	In thousands, except par values and share data	
Assets		
Current assets:		
Cash and cash equivalents	$ 58,546	$ 35,729
Receivables:		
Crude oil and natural gas sales	546,560	468,650
Affiliated parties	12,329	12,410
Joint interest and other, net	356,624	356,111
Derivative assets	3,550	18,389
Inventories	61,739	46,743
Deferred and prepaid taxes	31,715	365
Prepaid expenses and other	9,529	8,386
Total current assets	1,080,592	946,783
Net property and equipment, based on successful efforts method of accounting	8,764,624	8,105,269
Net debt issuance costs and other	54,096	55,726
Noncurrent derivative assets	32,864	32,231
Total assets	$ 9,932,176	$ 9,140,009
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable trade	$ 734,948	$ 687,310
Revenues and royalties payable	261,787	261,856
Payables to affiliated parties	5,936	6,069
Accrued liabilities and other	133,661	153,454
Derivative liabilities	76,672	12,999
Current portion of asset retirement obligations	2,089	2,227
Current portion of long-term debt	1,965	1,950
Total current liabilities	1,217,058	1,125,865
Long-term debt, net of current portion	3,976,801	3,537,771
Other noncurrent liabilities:		
Deferred income tax liabilities	1,376,517	1,262,576
Asset retirement obligations, net of current portion	44,332	44,944
Noncurrent derivative liabilities	2,315	2,173
Other noncurrent liabilities	3,073	2,981
Total other noncurrent liabilities	1,426,237	1,312,674
Commitments and contingencies (Note 7)		
Shareholders equity:		

Preferred stock, $0.01 par value; 25,000,000 shares authorized; no shares issued and outstanding				
Common stock, $0.01 par value; 500,000,000 shares authorized; 185,632,612 shares issued and outstanding at March 31, 2013; 185,604,681 shares issued and outstanding at December 31, 2012		1,856		1,856
Additional paid-in capital		1,234,589		1,226,835
Retained earnings		2,075,635		1,935,008
Total shareholders equity		3,312,080		3,163,699
Total liabilities and shareholders equity	$	9,932,176	$	9,140,009

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

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Continental Resources, Inc. and Subsidiaries

Unaudited Condensed Consolidated Statements of Income

	Three months ended March 31, 2013	Three months ended March 31, 2012
	In thousands, except per share data	
Revenues		
Crude oil and natural gas sales	$ 762,632	$ 535,312
Crude oil and natural gas sales to affiliates	20,885	16,946
Loss on derivative instruments, net	(84,831)	(169,057)
Crude oil and natural gas service operations	11,543	11,899
Total revenues	710,229	395,100
Operating costs and expenses		
Production expenses	61,318	40,016
Production and other expenses to affiliates	1,657	1,069
Production taxes and other expenses	71,257	49,730
Exploration expenses	9,814	4,151
Crude oil and natural gas service operations	8,597	9,842
Depreciation, depletion, amortization and accretion	213,678	149,455
Property impairments	40,081	29,907
General and administrative expenses	33,817	24,966
Gain on sale of assets, net	(136)	(49,627)
Total operating costs and expenses	440,083	259,509
Income from operations	270,146	135,591
Other income (expense):		
Interest expense	(47,475)	(24,278)
Other	546	781
	(46,929)	(23,497)
Income before income taxes	223,217	112,094
Provision for income taxes	82,590	43,000
Net income	$ 140,627	$ 69,094
Basic net income per share	$ 0.76	$ 0.38
Diluted net income per share	$ 0.76	$ 0.38

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

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Continental Resources, Inc. and Subsidiaries

Condensed Consolidated Statements of Shareholders Equity

	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Total shareholders equity
		In thousands, except share data			
Balance at December 31, 2012	185,604,681	$ 1,856	$ 1,226,835	$ 1,935,008	$ 3,163,699
Net income (unaudited)				140,627	140,627
Stock-based compensation (unaudited)			9,242		9,242
Restricted stock:					
Issued (unaudited)	64,735				
Repurchased and canceled (unaudited)	(17,856)		(1,488)		(1,488)
Forfeited (unaudited)	(18,948)				
Balance at March 31, 2013	185,632,612	$ 1,856	$ 1,234,589	$ 2,075,635	$ 3,312,080

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

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Continental Resources, Inc. and Subsidiaries

Unaudited Condensed Consolidated Statements of Cash Flows

	Three months ended March 31, 2013	2012
Cash flows from operating activities	*In thousands*	
Net income	$ 140,627	$ 69,094
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	215,464	150,273
Property impairments	40,081	29,907
Change in fair value of derivatives	78,021	129,132
Stock-based compensation	9,242	5,515
Provision for deferred income taxes	82,590	40,850
Dry hole costs	2,261	88
Gain on sale of assets, net	(136)	(49,627)
Other, net	1,390	828
Changes in assets and liabilities:		
Accounts receivable	(78,118)	(19,921)
Inventories	(14,995)	(2,634)
Prepaid expenses and other	(984)	1,484
Accounts payable trade	5,068	(1,768)
Revenues and royalties payable	(69)	5,778
Accrued liabilities and other	(22,340)	5,948
Other noncurrent assets and liabilities	9	(3)
Net cash provided by operating activities	458,111	364,944
Cash flows from investing activities		
Exploration and development	(857,523)	(1,012,308)
Purchase of producing crude oil and natural gas properties	(3,332)	(57,662)
Purchase of other property and equipment	(12,649)	(9,963)
Proceeds from sale of assets	351	84,818
Net cash used in investing activities	(873,153)	(995,115)
Cash flows from financing activities		
Revolving credit facility borrowings	440,000	718,000
Repayment of revolving credit facility		(900,000)
Proceeds from issuance of Senior Notes		787,000
Proceeds from other debt		22,000
Repayment of other debt	(485)	(159)
Debt issuance costs	(168)	(3,843)
Repurchase of equity grants	(1,488)	(3,748)
Exercise of stock options		60
Net cash provided by financing activities	437,859	619,310
Net change in cash and cash equivalents	22,817	(10,861)
Cash and cash equivalents at beginning of period	35,729	53,544
Cash and cash equivalents at end of period	58,546	42,683

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

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note 1. Organization and Nature of Business

Description of the Company

Continental s principal business is crude oil and natural gas exploration, development and production with properties 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 and the Red River units. The South region includes Kansas and all properties south of Kansas and west of the Mississippi River including the South Central Oklahoma Oil Province (SCOOP), Northwest Cana, and Arkoma Woodford plays in Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River.

The Company s operations are geographically concentrated in the North region, with that region comprising approximately 77% of the Company s crude oil and natural gas production for the three months ended March 31, 2013. The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the three months ended March 31, 2013, crude oil accounted for approximately 71% of the Company s total production and approximately 88% of its crude oil and natural gas revenues.

Note 2. Basis of Presentation and Significant Accounting Policies

Basis of presentation

The condensed consolidated financial statements include the accounts of Continental and its wholly owned subsidiaries after all significant intercompany accounts and transactions have been eliminated upon consolidation.

This report has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC) applicable to interim financial information. Because this is an interim period filing presented using a condensed format, it does not include all disclosures required by accounting principles generally accepted in the United States (U.S. GAAP), although the Company believes the disclosures are adequate to make the information not misleading. You should read this Form 10-Q together with the Company s Annual Report on Form 10-K for the year ended December 31, 2012 (2012 Form 10-K), which includes a summary of the Company s significant accounting policies and other disclosures.

The condensed consolidated financial statements as of March 31, 2013 and for the three month periods ended March 31, 2013 and 2012 are unaudited. The condensed consolidated balance sheet as of December 31, 2012 was derived from the audited balance sheet included in the 2012 Form 10-K. The Company has evaluated events or transactions through the date this report on Form 10-Q was filed with the SEC in conjunction with its preparation of these condensed consolidated 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 are the estimates of the Company s crude oil and natural gas reserves, which are used to compute depreciation, depletion, amortization and impairment of proved 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 and consist of the following:

In thousands	March 31, 2013	December 31, 2012
Tubular goods and equipment	$ 15,251	$ 13,590

Crude oil		46,488		33,153
Total	$	61,739	$	46,743

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Crude oil inventories are valued at the lower of cost or market using the first-in, first-out inventory method. Crude oil inventories consist of the following volumes:

MBbls	**March 31, 2013**	**December 31, 2012**
Crude oil line fill requirements	422	391
Temporarily stored crude oil	378	211
Total	800	602

Earnings per share

Basic net income per share is computed by dividing net income by the weighted-average number of shares outstanding for the period. Diluted net income per share reflects the potential dilution of non-vested restricted stock awards and stock options, which are calculated using the treasury stock method as if the awards and options were exercised. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income per share for the three months ended March 31, 2013 and 2012:

	Three months ended March 31,	
	2013	**2012**
	In thousands, except per share data	
Income (numerator):		
Net income - basic and diluted	$ 140,627	$ 69,094
Weighted average shares (denominator):		
Weighted average shares - basic	183,999	179,707
Non-vested restricted stock	657	512
Stock options		64
Weighted average shares - diluted	184,656	180,283
Net income per share:		
Basic	$ 0.76	$ 0.38
Diluted	$ 0.76	$ 0.38

Adoption of new accounting standard

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities*. The new standard requires an entity to disclose information about offsetting arrangements to enable financial statement users to understand the effect of netting arrangements on an entity s financial position. The disclosures are required for recognized financial instruments and derivative instruments that are subject to offsetting under current accounting literature or are subject to master netting arrangements irrespective of whether they are offset. The disclosure requirements became effective for periods beginning on or after January 1, 2013 and must be applied retrospectively to all periods presented on the balance sheet. The Company adopted the provisions of the new standard on January 1, 2013 and has included the required disclosures in *Note 4. Derivative Instruments*. Adoption of the new standard required additional footnote disclosures for our derivative instruments and did not have an impact on our financial position, results of operations or cash flows.

Note 3. 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 assets and liabilities but does not result in cash receipts or payments.

	Three months ended March 31,	
	2013	2012
	In thousands	
Supplemental cash flow information:		
Cash paid for interest	$ 53,169	$ 2,915
Cash paid for income taxes	11,049	626
Cash received for income tax refunds	(8)	(5)
Non-cash investing activities:		
Increase (decrease) in accrued capital expenditures	42,214	(37,439)
Asset retirement obligations, net	2,227	1,762

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Note 4. Derivative Instruments

The Company is required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized changes in fair value in the unaudited condensed consolidated statements of income under the caption Loss on derivative instruments, net.

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 limits future revenues from upward price movements.

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 a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. 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 a 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 between the floor price and the ceiling price.

The Company s derivative contracts are settled based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX West Texas Intermediate (WTI) pricing or Inter-Continental Exchange (ICE) pricing for Brent crude oil and natural gas derivative settlements based on NYMEX Henry Hub pricing. The estimated fair value of derivative contracts is based upon various factors, including commodity exchange prices, over-the-counter quotations, and, in the case of collars, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars requires the use of an option-pricing model. See *Note 5. Fair Value Measurements*.

At March 31, 2013, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below.

Crude Oil - NYMEX WTI		Swaps	Collars: Floors		Collars: Ceilings	
Period and Type of Contract	**Bbls**	**Weighted Average Price**	**Range**	**Weighted Average Price**	**Range**	**Weighted Average Price**
April 2013 - December 2013						
Swaps - WTI	8,937,500	$ 92.66				
Collars - WTI	6,600,000		$ 80.00 - $95.00	$ 86.92	$ 92.30 - $110.33	$ 99.46
January 2014 - December 2014						
Swaps - WTI	10,311,250	$ 96.20				

Crude Oil - ICE Brent		Swaps	Collars: Floors		Collars: Ceilings	
Period and Type of Contract	**Bbls**	**Weighted Average Price**	**Range**	**Weighted Average Price**	**Range**	**Weighted Average Price**
April 2013 - December 2013						
Swaps - ICE Brent	3,712,500	$ 108.72				
January 2014 - December 2014						
Swaps - ICE Brent	11,862,500	$ 102.83				
Collars - ICE Brent	2,190,000		$ 90.00 - $95.00	$ 90.83	$ 104.70 - $108.85	$ 107.13
January 2015 - December 2015						

Swaps - ICE Brent	1,277,500	$ 98.48

Natural Gas - NYMEX Henry Hub

Period and Type of Contract	**MMBtus**	**Swaps Weighted Average Price**
April 2013 - December 2013		
Swaps - Henry Hub	68,750,000	$ 3.78
January 2014 - December 2014		
Swaps - Henry Hub	40,150,000	$ 4.14

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Derivative gains and losses

The following table presents realized and unrealized gains and losses on derivative instruments for the periods presented.

	Three months ended March 31, 2013	2012
	In thousands	
Realized gain (loss) on derivatives:		
Crude oil fixed price swaps	$ (9,593)	$ (31,424)
Crude oil collars	125	(10,920)
Natural gas fixed price swaps	2,658	2,419
Realized loss on derivatives, net	$ (6,810)	$ (39,925)
Unrealized gain (loss) on derivatives:		
Crude oil fixed price swaps	$ (33,364)	$ (80,998)
Crude oil collars	(13,762)	(58,943)
Natural gas fixed price swaps	(30,895)	10,809
Unrealized loss on derivatives, net	$ (78,021)	$ (129,132)
Loss on derivative instruments, net	$ (84,831)	$ (169,057)

Balance sheet offsetting of derivative assets and liabilities

In December 2011, the FASB issued ASU No. 2011-11, *Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities*, which requires an entity to disclose information about offsetting arrangements to enable financial statement users to understand the effect of netting arrangements on an entity s financial position. The Company adopted the provisions of the new standard on January 1, 2013 as required and has provided the applicable disclosures below with respect to its derivative instruments.

All of the Company s derivative contracts are carried at their fair value in the condensed consolidated balance sheets under the captions Derivative assets , Noncurrent derivative assets , Derivative liabilities , and Noncurrent derivative liabilities . Derivative assets and liabilities with the same counterparty that are subject to contractual terms which provide for net settlement are reported on a net basis in the condensed consolidated balance sheets.

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the condensed consolidated balance sheets for the periods presented, all at fair value.

	March 31, 2013			December 31, 2012		
In thousands	Gross amounts of recognized assets	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet	Gross amounts of recognized assets	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet
Commodity derivative assets	$ 53,705	$ (17,291)	$ 36,414	$ 86,506	$ (35,886)	$ 50,620

	March 31, 2013			December 31, 2012		
In thousands	**Gross amounts of recognized liabilities**	**Gross amounts offset on balance sheet**	**Net amounts of liabilities on balance sheet**	**Gross amounts of recognized liabilities**	**Gross amounts offset on balance sheet**	**Net amounts of liabilities on balance sheet**
Commodity derivative liabilities	$ (95,742)	$ 16,755	$ (78,987)	$ (16,241)	$ 1,069	$ (15,172)

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Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

The following table reconciles the net amounts disclosed above to the individual financial statement line items in the condensed consolidated balance sheets.

In thousands	March 31, 2013	December 31, 2012
Derivative assets	$ 3,550	$ 18,389
Noncurrent derivative assets	32,864	32,231
Net amounts of assets on balance sheet	$ 36,414	$ 50,620
Derivative liabilities	$ (76,672)	$ (12,999)
Noncurrent derivative liabilities	(2,315)	(2,173)
Net amounts of liabilities on balance sheet	$ (78,987)	$ (15,172)
Total derivative assets (liabilities), net	$ (42,573)	$ 35,448

Note 5. Fair Value Measurements

The Company follows a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2: Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3: Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management s best estimate of fair value.

A financial instrument s categorization within the hierarchy is based upon the lowest level of input that is significant to the fair value measurement. Level 1 inputs are given the highest priority in the fair value hierarchy while Level 3 inputs are given the lowest priority. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the hierarchy. As Level 1 inputs generally provide the most reliable evidence of fair value, the Company uses Level 1 inputs when available. The Company s policy is to recognize transfers between the hierarchy levels as of the beginning of the reporting period in which the event or change in circumstances caused the transfer.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company s derivative instruments. In determining the fair values of fixed price swaps, a discounted cash flow method is used due to the unavailability of relevant comparable market data for the Company s exact contracts. The discounted cash flow method estimates future cash flows based on quoted market prices for forward commodity prices and a risk-adjusted discount rate. The fair values of fixed price swaps are calculated mainly using significant observable inputs (Level 2). Calculation of the fair values of collar contracts requires the use of an industry-standard option pricing model that considers various inputs including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. These assumptions are observable in the marketplace or can be corroborated by active markets or broker quotes and are therefore designated as Level 2 within the valuation hierarchy. The Company s calculation for each of its derivative positions is compared to the counterparty valuation for reasonableness.

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Notes to Unaudited Condensed Consolidated Financial Statements

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of March 31, 2013 and December 31, 2012.

	Fair value measurements at March 31, 2013 using:			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
		In thousands		
Derivative assets (liabilities):				
Fixed price swaps	$	$ (27,543)	$	$ (27,543)
Collars		(15,030)		(15,030)
Total	$	$ (42,573)	$	$ (42,573)

	Fair value measurements at December 31, 2012 using:			
Description	**Level 1**	**Level 2**	**Level 3**	**Total**
		In thousands		
Derivative assets (liabilities):				
Fixed price swaps	$	$ 36,716	$	$ 36,716
Collars		(1,268)		(1,268)
Total	$	$ 35,448	$	$ 35,448

Assets Measured at Fair Value on a Nonrecurring Basis

Certain assets 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 for those assets.

Asset Impairments Proved crude oil and natural gas properties are reviewed for impairment on a field-by-field basis each quarter, or when events and circumstances indicate a possible decline in the recoverability of the carrying value of such field. The estimated future cash flows expected in connection with the field are compared to the carrying amount of the field to determine if the carrying amount is recoverable. If the carrying amount of the field exceeds its estimated undiscounted future cash flows, the carrying amount of the field 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 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). The following table sets forth quantitative information about the significant unobservable inputs used by the Company to calculate the fair value of proved crude oil and natural gas properties using a discounted cash flow method.

Unobservable Input	**Assumption**
Future production	Future production estimates for each property
Forward commodity prices	Forward NYMEX swap prices through 2017 (adjusted for differentials), escalating 3% per year thereafter
Operating and development costs	Estimated costs for the current year, escalating 3% per year thereafter
Productive life of field	Ranging from 0 to 50 years
Discount rate	10%

Unobservable inputs to the fair value assessment are reviewed quarterly and are revised as warranted based on a number of factors, including reservoir performance, new drilling, crude oil and natural gas prices, changes in costs, technological advances, new geological or geophysical data, or other economic factors. Fair value measurements of proved properties are reviewed and approved by certain members of the Company s management.

Proved properties were reviewed for impairment at March 31, 2013 and 2012. For those periods, future cash flows were determined to be in excess of cost basis, therefore no impairment was recorded for the Company s proved crude oil and natural gas properties.

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Notes to Unaudited Condensed Consolidated Financial Statements

Certain unproved crude oil and natural gas properties were impaired during the three months ended March 31, 2013 and 2012, reflecting recurring amortization of undeveloped leasehold costs on properties that management expects will not be transferred to proved properties over the lives of the leases based on experience of successful drilling and the average holding period.

The following table sets forth the non-cash impairments of both proved and unproved properties for the indicated periods. Proved and unproved property impairments are recorded under the caption Property impairments in the unaudited condensed consolidated statements of income.

	Three months ended March 31, 2013	2012
	In thousands	
Proved property impairments	$	$
Unproved property impairments	40,081	29,907
Total	$ 40,081	$ 29,907

Financial Instruments Not Recorded at Fair Value

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

In thousands	March 31, 2013 Carrying Amount	Fair Value	December 31, 2012 Carrying Amount	Fair Value
Debt:				
Revolving credit facility	$ 1,035,000	$ 1,035,000	$ 595,000	$ 595,000
Note payable	19,936	19,432	20,421	20,148
8 1/4% Senior Notes due 2019	298,138	334,250	298,085	339,000
7 3/8% Senior Notes due 2020	198,586	225,167	198,552	226,833
7 1/8% Senior Notes due 2021	400,000	451,333	400,000	454,333
5% Senior Notes due 2022	2,027,106	2,120,833	2,027,663	2,165,833
Total debt	$ 3,978,766	$ 4,186,015	$ 3,539,721	$ 3,801,147

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

The fair value of the note payable is determined using a discounted cash flow approach based on the interest rate and payment terms of the note payable and an assumed discount rate. The fair value of the note payable is significantly influenced by the discount rate assumption, which is derived by the Company and is unobservable. Accordingly, the fair value of the note payable is classified as Level 3 in the fair value hierarchy.

The fair values of the 8 1/4% Senior Notes due 2019 (the 2019 Notes), the 7 3/8% Senior Notes due 2020 (the 2020 Notes), the 7 1/8% Senior Notes due 2021 (the 2021 Notes) and the 5% Senior Notes due 2022 (the 2022 Notes) are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

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 6. Long-Term Debt

Long-term debt consists of the following:

	March 31, 2013	December 31, 2012
	In thousands	
Revolving credit facility	$ 1,035,000	$ 595,000
Note payable	19,936	20,421
8 1/4% Senior Notes due 2019(1)	298,138	298,085
7 3/8% Senior Notes due 2020(2)	198,586	198,552
7 1/8% Senior Notes due 2021(3)	400,000	400,000
5% Senior Notes due 2022(4)	2,027,106	2,027,663
Total debt	3,978,766	3,539,721
Less: Current portion of long-term debt	(1,965)	(1,950)
Long-term debt, net of current portion	$ 3,976,801	$ 3,537,771

(1) The carrying amount is net of unamortized discounts of $1.9 million at both March 31, 2013 and December 31, 2012.

(2) The carrying amount is net of unamortized discounts of $1.4 million at both March 31, 2013 and December 31, 2012.

(3) These notes were sold at par and are recorded at 100% of face value.

(4) The carrying amount includes an unamortized premium of $27.1 million and $27.7 million at March 31, 2013 and December 31, 2012, respectively.

Continental Resources, Inc. and Subsidiaries

Notes to Unaudited Condensed Consolidated Financial Statements

Revolving Credit Facility

The Company had $1,035.0 million of outstanding borrowings at March 31, 2013 on its credit facility, which matures on July 1, 2015. At December 31, 2012, the Company had $595.0 million of outstanding borrowings on its credit facility. The credit facility had aggregate commitments of $1.5 billion and a borrowing base of $3.25 billion at March 31, 2013, subject to semi-annual redetermination. The terms of the facility allow for the commitment level to be increased up to the lesser of the borrowing base then in effect or $2.5 billion. Borrowings under the facility bear interest 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 150 to 250 basis points, depending on the percentage of the borrowing base utilized, or the lead bank s reference rate (prime) plus a margin ranging from 50 to 150 basis points. Credit facility borrowings are required to be secured by the Company s interest in at least 80% (by value) of all of its proved reserves and associated crude oil and natural gas properties unless the Collateral Coverage Ratio, as defined in the amended credit facility, is greater than or equal to 1.75 to 1.0, in which case the 80% requirement will not apply.

The Company had approximately $460.2 million of unused commitments (after considering outstanding borrowings and letters of credit) under its credit facility at March 31, 2013 and incurs commitment fees of 0.375% 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 and a ratio of total funded debt to EBITDAX of no greater than 4.0 to 1.0. As defined by the credit facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit facility and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided in *Part I, Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit on the credit facility plus the Company s note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. The Company was in compliance with these covenants at March 31, 2013.

See Note 10. Subsequent Events for a discussion of the amendment made to the Company s credit facility subsequent to March 31, 2013.

Senior Notes

The following table summarizes the maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company s outstanding senior note obligations at March 31, 2013.

	2019 Notes	**2020 Notes**	**2021 Notes**	**2022 Notes**
Maturity date	October 1, 2019	October 1, 2020	April 1, 2021	September 15, 2022
Interest payment dates	April 1, October 1	April 1, October 1	April 1, October 1	March 15, Sept. 15
Call premium redemption period (1)	October 1, 2014	October 1, 2015	April 1, 2016	March 15, 2017
Make-whole redemption period (2)	October 1, 2014	October 1, 2015	April 1, 2016	March 15, 2017
Equity offering redemption period (3)		October 1, 2013	April 1, 2014	March 15, 2015

(1) On or after these dates, the Company has the option to redeem all or a portion of its senior notes at the decreasing redemption prices specified in the respective senior note indentures (together, the Indentures) plus any accrued and unpaid interest to the date of redemption.

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(2) At any time prior to these dates, the Company has the option to redeem all or a portion of its senior notes at the make-whole redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption.

(3) At any time prior to these dates, the Company may redeem up to 35% of the principal amount of its senior notes under certain circumstances with the net cash proceeds from one or more equity offerings at the redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption. The optional redemption period for the 2019 Notes using equity offering proceeds expired on October 1, 2012.

The Company s senior notes are not subject to any mandatory redemption or sinking fund requirements.

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 at March 31, 2013. Two of the Company s subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have insignificant assets with no current value and no operations, fully and unconditionally, guarantee the senior notes. The Company s other subsidiary, 20 North Broadway Associates LLC, the value of whose assets and operations are minor, does not guarantee the senior notes.

See *Note 10. Subsequent Events* for a discussion of the new senior notes issued by the Company subsequent to March 31, 2013.

Note Payable

In February 2012, 20 North Broadway Associates LLC, a wholly-owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company s corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan s maturity date of February 26, 2022. Accordingly, approximately $2.0 million is reflected as a current liability under the caption Current portion of long-term debt in the condensed consolidated balance sheets as of March 31, 2013.

Note 7. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of March 31, 2013. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments As of March 31, 2013, the Company had drilling rig contracts with various terms extending through August 2014. These contracts were entered into in the ordinary course of business to ensure rig availability to allow the Company to execute its business objectives in its key strategic plays. Future commitments as of March 31, 2013 total approximately $82 million, of which $65 million is expected to be incurred in the remainder of 2013 and $17 million in 2014.

Fracturing and well stimulation service agreement The Company has an agreement with a third party whereby the third party will 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 term of the agreement ends in September 2013. Pursuant to the take-or-pay provisions, the Company is to pay a fixed rate per day for a minimum number of days per calendar quarter regardless of whether the services are provided. The agreement also stipulates the Company will bear the cost of certain products and materials used. Future commitments remaining as of March 31, 2013 amount to approximately $11 million, which is expected to be incurred up through September 2013. Since the inception of this agreement, the Company has been using the services more than the minimum number of days each quarter.

Pipeline transportation commitments The Company has entered into firm transportation commitments to guarantee pipeline access capacity totaling 15,000 barrels of crude oil per day on operational pipelines in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The commitments, which have 5-year terms extending as far as November 2017, require the Company to pay varying per-barrel transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of March 31, 2013 under the operational pipeline transportation arrangements amount to approximately $52 million, of which $10 million is expected to be incurred in the remainder of 2013, $13 million in 2014, $13 million in 2015, $10 million in 2016 and $6 million in 2017.

Further, the Company is a party to additional 5-year firm transportation commitments for future pipeline projects being considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require significant additional construction efforts by our counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.0 billion at March 31, 2013, representing aggregate transportation charges expected to be

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incurred over the 5-year terms of the arrangements assuming the proposed pipeline projects are completed and become operational. The timing of the commencement of pipeline operations is not known due to uncertainties involving matters such as regulatory approvals, resolution of legal and environmental disputes, construction progress and the ultimate probability of pipeline completion. Accordingly, the timing of the Company s obligations under these non-operational arrangements cannot be predicted with certainty and may not be incurred on a ratable basis over a calendar year or may not be incurred at all. Although timing is uncertain, the Company s obligations under these arrangements are not expected to begin until at least 2014.

Rail transportation commitments The Company has entered into firm transportation commitments to guarantee capacity on rail transportation facilities in order to reduce the impact of possible curtailments that may arise due to limited transportation capacity. The rail commitments have various terms extending through December 2015 and require the Company to pay varying per-barrel transportation charges on volumes ranging from 2,500 to 10,000 barrels of crude oil per day regardless of the amount of rail capacity used. Future commitments remaining as of March 31, 2013 under the rail transportation arrangements amount to approximately $43 million, of which $26 million is expected to be incurred in the remainder of 2013, $10 million in 2014 and $7 million in 2015.

The Company s pipeline and rail transportation commitments are for crude oil production in the North region where the Company allocates a significant portion of its capital expenditures. The Company is not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

Litigation In November 2010, an alleged class action was filed against the Company alleging the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners as categorized in the petition from crude oil and natural gas wells located in Oklahoma. The plaintiffs have alleged a number of claims, including breach of contract, fraud, breach of fiduciary duty, unjust enrichment, and other claims and seek recovery of compensatory damages, interest, punitive damages and attorney fees on behalf of the alleged class. The Company has responded to the petition, denied the allegations and raised a number of affirmative defenses. Discovery is ongoing and information and documents continue to be exchanged. The Company is not currently able to estimate a reasonably possible loss or range of loss or what impact, if any, the action will have on its financial condition, results of operations or cash flows due to the preliminary status of the matter, the complexity and number of legal and factual issues presented by the matter and uncertainties with respect to, among other things, the nature of the claims and defenses, the potential size of the class, the scope and types of the properties and agreements involved, the production years involved, and the ultimate potential outcome of the matter. The class has not been certified. Plaintiffs have indicated that if the class is certified they may seek damages in excess of $145 million, a majority of which would be comprised of interest. The Company disputes plaintiffs claims, disputes that the case meets the requirements for a class action and is vigorously defending the case.

The Company is involved in various other legal proceedings such as commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims and similar matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. As of March 31, 2013 and December 31, 2012, the Company has recorded a liability in the condensed consolidated balance sheets under the caption Other noncurrent liabilities of $2.5 million and $2.4 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 8. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to 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 unaudited condensed consolidated statements of income, is reflected in the table below for the periods presented.

	Three months ended March 31,	
	2013	2012

	In thousands	
Non-cash equity compensation	$ 9,242	$ 5,515

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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 March 31, 2013, the Company had 1,840,036 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 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.

A summary of changes in non-vested restricted stock shares outstanding for the three months ended March 31, 2013 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2012	1,629,462	$ 63.28
Granted	64,735	83.89
Vested	(57,157)	69.00
Forfeited	(18,948)	84.35
Non-vested restricted shares outstanding at March 31, 2013	1,618,092	$ 66.23

The grant date fair value of restricted stock represents the average of the high and low intraday market prices of the Company s common stock on the date of grant. Compensation expense for a restricted stock grant is a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. The expected life of restricted stock is based on the non-vested period that remains subsequent to the date of grant. There are no post-vesting restrictions related to the Company s restricted stock. The fair value of restricted stock that vested during the three months ended March 31, 2013 at the vesting date was approximately $4.7 million. As of March 31, 2013, there was approximately $68 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized over a weighted average period of 1.8 years.

Note 9. 2012 Property Disposition

In February 2012, the Company assigned certain non-strategic leaseholds and producing properties located in Wyoming to a third party for cash proceeds of $84.4 million. In connection with the transaction, the Company recognized a pre-tax gain of $50.1 million. The disposed properties comprised 3.2 MMBoe, or 1%, of the Company s total proved reserves at December 31, 2011 and 259 MBoe, or 1%, of its 2011 total crude oil and natural gas production. The gain on the transaction is included in Gain on sale of assets, net in the unaudited condensed consolidated statements of income for the three months ended March 31, 2012.

Note 10. Subsequent Events

Amendment to Revolving Credit Facility

On April 3, 2013, certain terms of the Company s credit facility were amended. The amendment included, among other things, the following changes:

Allows the Company to elect to suspend the need to comply with borrowing base requirements under the credit facility if either Moody s or Standard & Poor s (S&P) rates the Company s senior unsecured debt at or above Ba1 (in the case of Moody s) or BB+ (in the case of S&P). Previously, the credit facility required both Moody s and S&P to provide those respective debt ratings before the Company could elect to suspend the borrowing base requirements.

Allows the Company to elect to release the collateral consisting of crude oil and natural gas properties if either Moody s or S&P rates the Company s senior unsecured debt at or above Baa3 (in the case of Moody s) or BBB- (in the case of S&P) (collectively, the Collateral Release Ratings), but requires the Company to continue certain reporting requirements and maintain a ratio of the Present Value, as defined in the amended credit facility, of the Company s crude oil and natural gas properties to all funded debt of the Company of not less than 1.75 to 1.0 (the Present Value Covenant) during the period that only one of Moody s or S&P has issued a rating at or above the Collateral Release Ratings. Previously, the credit facility required both Moody s and S&P to rate the Company s senior unsecured debt at or above the Collateral Release Ratings before the collateral from crude oil and natural gas properties could be released.

Provides that if at least one of Moody s or S&P has not rated the Company s senior unsecured debt at or above the Collateral Release Ratings, the Company must provide an acceptable security interest in the lesser of (i) crude oil and natural gas properties of the Company representing 80% of the Present Value of such properties and (ii) such of the Company s proved reserves and associated crude oil and natural gas properties sufficient to provide a Collateral Coverage Ratio, as defined in the amended credit facility, of at least 1.75 to 1.0.

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Provides that if both Moody s and S&P rate the Company s senior unsecured debt at or above the Collateral Release Ratings, the Company is not required to comply with certain reporting requirements and the Present Value Covenant and that the Company will again be required to comply with such reporting requirements and the Present Value Covenant at such time as both Moody s and S&P do not rate the Company s senior unsecured debt at or above the Collateral Release Ratings.

Issuance of New Senior Notes

On April 5, 2013, the Company issued $1.5 billion of 4 1/2% Senior Notes due 2023 (the 2023 Notes) and received net proceeds of approximately $1.48 billion after deducting the initial purchasers fees. The 2023 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 used a portion of the net proceeds from the offering to repay all borrowings then outstanding under its credit facility, which had a balance prior to payoff of approximately $1.04 billion, and expects to use the remaining net proceeds to fund a portion of its 2013 capital budget and for general corporate purposes. The 2023 Notes will mature on April 15, 2023 and interest is payable on the 2023 Notes on April 15 and October 15 of each year, commencing October 15, 2013.

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 the condensed consolidated financial statements and notes thereto included elsewhere in this report and our historical consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2012. Our operating results for the periods discussed below may not be indicative of future performance. The following discussion and analysis includes forward-looking statements and should be read in conjunction with the risk factors described under the heading *Part II, Item 1A. Risk Factors* included in this report, if any, and in our Annual Report on Form 10-K for the year ended December 31, 2012, along with *Cautionary Statement for the Purpose of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995* 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 an independent crude oil and natural gas exploration and production company with properties 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, and the Red River units. The South region includes Kansas and all properties south of Kansas and west of the Mississippi River including the South Central Oklahoma Oil Province (SCOOP), Northwest Cana, and Arkoma Woodford plays in Oklahoma. The SCOOP and Northwest Cana plays were previously combined by us and referred to as the Anadarko Woodford play. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River. Our operations are geographically concentrated in the North region, with that region comprising approximately 77% of our crude oil and natural gas production for the three months ended March 31, 2013.

We focus our exploration activities in large new or developing crude oil and liquids-rich natural gas 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. In October 2012, we announced a new five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017.

We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas. We expect growth in our revenues and operating income will primarily depend on commodity 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 affect crude oil and natural gas prices. In addition, the prices we realize for our crude oil and natural gas production are affected by price differences in the markets where we deliver our production.

First Quarter 2013 Highlights

Production, revenues and operating cash flows

For the first quarter of 2013, our crude oil and natural gas production averaged 121,532 Boe per day, a 14% increase over average daily production of 106,831 Boe per day for the fourth quarter of 2012 and a 42% increase over average daily production of 85,526 Boe per day for the first quarter of 2012. Crude oil represented 71% of our total production for the three months ended March 31, 2013 compared to 70% for the comparable 2012 period.

The increase in 2013 production was primarily driven by higher production from our properties in the North Dakota Bakken field and the SCOOP play due to the continued success of our drilling programs in those areas, along with incremental production added from property acquisitions made in 2012. Our Bakken production in North Dakota averaged 67,575 Boe per day for the first quarter of 2013, a 14% increase over the fourth quarter of 2012 and 61% higher than the first quarter of 2012. Our production in the emerging SCOOP play averaged 14,243 Boe per day for the first quarter of 2013, an increase of 100% over the fourth quarter of 2012 and 462% higher than the 2012 first quarter.

Our crude oil and natural gas revenues for the first quarter of 2013 increased 42% to $783.5 million primarily due to a 40% increase in sales volumes along with a 1% increase in realized commodity prices when compared to the first quarter of 2012. Crude oil represented 88% of our total crude oil and natural gas revenues for the first quarter of 2013 compared to 89% for the first quarter of 2012.

Our cash flows from operating activities for the first quarter of 2013 were $458.1 million, a 26% increase from $364.9 million provided by our operating activities during the comparable 2012 period. The increase in operating cash flows was primarily due to increased crude oil and natural gas revenues driven by increased sales volumes coupled with lower realized losses on derivatives, partially offset by higher production expenses, production taxes, general and administrative expenses, and other expenses associated with the growth of our operations over the past year.

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Issuance of new senior notes subsequent to quarter-end

On April 5, 2013, we issued $1.5 billion of 4 1/2% Senior Notes due 2023 (the 2023 Notes) and received net proceeds of approximately $1.48 billion after deducting the initial purchasers fees. We used a portion of the net proceeds from the offering to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of approximately $1.04 billion. We expect to use the remaining net proceeds of approximately $0.4 billion to fund a portion of our 2013 capital budget and for general corporate purposes. The 2023 Notes will mature on April 15, 2023 and interest is payable on the 2023 Notes on April 15 and October 15 of each year, commencing October 15, 2013. As of April 30, 2013, we had $1.5 billion of borrowing availability on our credit facility with no borrowings outstanding.

Capital expenditures

Our capital expenditures budget for 2013 is $3.6 billion, excluding acquisitions. During the first quarter of 2013, we invested approximately $920.9 million, including unbudgeted acquisitions of $22.0 million, in our capital program (including $5.3 million of seismic costs and $42.2 million of capital costs associated with increased accruals for capital expenditures), focusing primarily on increased exploration and development in the Bakken field of North Dakota and Montana and the SCOOP play in south-central Oklahoma. We expect to continue participating as a buyer of properties if and when we have the ability to increase our position in strategic plays at favorable terms.

We hedge a portion of our anticipated future production to achieve more predictable cash flows and reduce our exposure to fluctuations in commodity prices. Reducing our exposure to price volatility helps ensure adequate funds are available for our capital program. We expect our cash flows from operations, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to meet our budgeted capital expenditure needs for 2013; however, we may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms.

Financial and operating highlights

We use a variety of financial and operating 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 (a non-GAAP financial measure).

The following table presents financial and operating highlights for the periods presented.

	Three months ended March 31, 2013	2012
Average daily production:		
Crude oil (Bbl per day)	86,071	59,901
Natural gas (Mcf per day)	212,766	153,751
Crude oil equivalents (Boe per day)	121,532	85,526
Average sales prices: [1]		
Crude oil ($/Bbl)	$ 89.99	$ 90.58
Natural gas ($/Mcf)	4.99	4.48
Crude oil equivalents ($/Boe)	72.31	71.39
Production expenses ($/Boe) [1]	5.70	5.18

General and administrative expenses ($/Boe) [(1)]	3.11	3.23
Net income (in thousands)	140,627	69,094
Diluted net income per share	0.76	0.38
EBITDAX (in thousands) [(2)]	621,528	454,532

(1) Average sales prices and per unit expenses have been calculated using sales volumes and exclude any effect of derivative transactions.

(2) EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided subsequently under the heading *Non-GAAP Financial Measures*.

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Three months ended March 31, 2013 compared to the three months ended March 31, 2012

Results of Operations

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

	Three months ended March 31, 2013	2012
	In thousands, except sales price data	
Crude oil and natural gas sales	$ 783,517	$ 552,258
Loss on derivative instruments, net (1)	(84,831)	(169,057)
Crude oil and natural gas service operations	11,543	11,899
Total revenues	710,229	395,100
Operating costs and expenses	(440,083)	(259,509)
Other expenses, net	(46,929)	(23,497)
Income before income taxes	223,217	112,094
Provision for income taxes	(82,590)	(43,000)
Net income	$ 140,627	$ 69,094
Production volumes:		
Crude oil (MBbl) (2)	7,746	5,451
Natural gas (MMcf)	19,149	13,991
Crude oil equivalents (MBoe)	10,938	7,783
Sales volumes:		
Crude oil (MBbl) (2)	7,645	5,404
Natural gas (MMcf)	19,149	13,991
Crude oil equivalents (MBoe)	10,836	7,736
Average sales prices: (3)		
Crude oil ($/Bbl)	$ 89.99	$ 90.58
Natural gas ($/Mcf)	4.99	4.48
Crude oil equivalents ($/Boe)	72.31	71.39

(1) Amounts include unrealized non-cash mark-to-market losses on derivatives of $78.0 million and $129.1 million for the three month periods ended March 31, 2013 and March 31, 2012, respectively.

(2) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or transportation constraints or we have sold crude oil from inventory. These actions result in differences between produced and sold crude oil volumes. Crude oil sales volumes were 101 MBbls less than crude oil production for the three months ended March 31, 2013 and 47 MBbls less than crude oil production for the three months ended March 31, 2012.

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

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Production

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

	Three months ended March 31, 2013		2012			
	Volume	Percent	Volume	Percent	Volume increase	Volume percent increase
Crude oil (MBbl)	7,746	71%	5,451	70%	2,295	42%
Natural gas (MMcf)	19,149	29%	13,991	30%	5,158	37%
Total (MBoe)	10,938	100%	7,783	100%	3,155	41%

	Three months ended March 31, 2013		2012			
	MBoe	Percent	MBoe	Percent	Volume increase (decrease)	Volume percent increase (decrease)
North Region	8,392	77%	5,905	76%	2,487	42%
South Region	2,546	23%	1,770	23%	776	44%
East Region (1)	-	0%	108	1%	(108)	-100%
Total	10,938	100%	7,783	100%	3,155	41%

(1) In December 2012, we sold the producing crude oil and natural gas properties in our East region and no new wells have been subsequently drilled in that region. Accordingly, no production is reflected for the East region for the three months ended March 31, 2013.

Crude oil production volumes increased 42% during the three months ended March 31, 2013 compared to the three months ended March 31, 2012. Production increases in the Bakken field and SCOOP play contributed incremental production volumes in 2013 of 2,506 MBbls, a 66% increase over production in these areas for the first quarter of 2012. Production growth in these areas is primarily due to increased drilling and completion activity resulting from our drilling program, along with incremental production added from property acquisitions made in 2012. These increases were partially offset by a decrease of 132 MBbls associated with non-strategic properties in Wyoming and the East region that were sold in February 2012 and December 2012, respectively. Additionally, production from our properties in the Red River units and Northwest Cana play decreased a total of 66 MBbls, or 5%, over the prior year first quarter due to a combination of natural declines in production and reduced drilling activity in those areas.

Natural gas production volumes increased 5,158 MMcf, or 37%, during the three months ended March 31, 2013 compared to the same period in 2012. Natural gas production in the Bakken field increased 2,199 MMcf, or 59%, for the three months ended March 31, 2013 compared to the same period in 2012 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in the play, along with incremental production added from property acquisitions made in 2012. Natural gas production in the SCOOP play increased 4,393 MMcf, or 411%, due to additional wells being completed and producing in the three months ended March 31, 2013 compared to the same period in 2012. Further, natural gas production increased 151 MMcf, or 42%, in non-Bakken areas of our North region due to the completion of new wells subsequent to the 2012 first quarter. These increases were partially offset by decreases in production volumes totaling 1,426 MMcf, or 17%, from our properties in Northwest Cana, Arkoma Woodford, and non-core areas in our South region due to a combination of natural declines in production and reduced drilling activity prompted by the pricing environment for natural gas in those areas. For 2013, we are allocating a greater portion of our capital expenditures to crude oil and liquids-rich areas such as the Bakken field and SCOOP play and have deferred our drilling activity in the Northwest Cana and Arkoma Woodford plays, which typically contain higher concentrations of natural gas. Additionally, natural gas production decreased 87 MMcf associated with non-strategic properties in Wyoming and the East region that were sold in February 2012 and December 2012, respectively.

Revenues

Our total revenues consist of sales of crude oil and natural gas, realized and unrealized changes in the fair value of our derivative instruments and revenues associated with crude oil and natural gas service operations.

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for the three months ended March 31, 2013 were $783.5 million, a 42% increase from sales of $552.3 million for the same period in 2012. Our sales volumes increased 3,100 MBoe, or 40%, over the comparable period in 2012 primarily due to the success of our drilling programs in the North Dakota Bakken field and SCOOP play.

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Our realized price per Boe increased $0.92 to $72.31 for the three months ended March 31, 2013 from $71.39 for the three months ended March 31, 2012. This increase reflects a significant improvement in crude oil differentials realized in the 2013 first quarter compared to the 2012 first quarter, which served to offset the decrease in index crude oil prices in effect between those periods. The differential between NYMEX calendar month average crude oil prices and our realized crude oil price per barrel for the three months ended March 31, 2013 decreased to $4.29 per barrel compared to $12.27 for the three months ended March 31, 2012 and $9.06 for the year ended December 31, 2012. The improved differential primarily reflects our ability to market and deliver our Bakken crude oil to premium markets throughout the United States, with an increased reliance on rail transportation versus pipeline transportation. During 2012, using rail transportation we began accessing new market centers on the east and west coasts of the United States and expanded our marketing efforts along the U.S. gulf coast. This approach provided flexibility to allow us to shift sales of our Bakken crude oil to markets that provide the most favorable pricing. The positive effects of stronger sales pricing in coastal U.S. markets began to be realized in the fourth quarter of 2012 and continued into the first quarter of 2013. We expect rail transportation will continue to take a prominent role in our crude oil deliveries out of the North region throughout the remainder of 2013.

Derivatives. We have entered into a number of derivative instruments, including fixed price swaps and zero-cost collars, to reduce the uncertainty of future cash flows in order to underpin our capital expenditures and drilling program. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the realized and unrealized changes in fair value in the unaudited condensed consolidated statements of income under the caption Loss on derivative instruments, net , which is a component of total revenues.

Changes in commodity futures price strips during the first quarter of 2013 had a negative impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $84.8 million for the three months ended March 31, 2013. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices. The following table presents the impact on total revenues related to realized and unrealized gains and losses on derivative instruments for the periods presented.

	Three months ended March 31, 2013	2012
	In thousands	
Realized gain (loss) on derivatives:		
Crude oil derivatives	$ (9,468)	$ (42,344)
Natural gas derivatives	2,658	2,419
Realized loss on derivatives, net	$ (6,810)	$ (39,925)
Unrealized gain (loss) on derivatives:		
Crude oil derivatives	$ (47,126)	$ (139,941)
Natural gas derivatives	(30,895)	$ 10,809
Unrealized loss on derivatives, net	$ (78,021)	$ (129,132)
Loss on derivative instruments, net	$ (84,831)	$ (169,057)

The unrealized mark-to-market losses reflected above at March 31, 2013 relate to derivative instruments with various terms that are scheduled to be realized over the period from April 2013 to December 2015. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at March 31, 2013.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 54% to $61.8 million during the three months ended March 31, 2013 from $40.1 million during the three months ended March 31, 2012. This increase is primarily the result of higher production volumes from an increase in the number of producing wells. Production expense per Boe was $5.70 for the three months ended March 31, 2013 compared to $5.18 per Boe for the three months ended March 31, 2012 and $5.49 per Boe for the year ended December 31, 2012. Contributing to the per-Boe increase were increases in well site and road maintenance costs and saltwater disposal costs resulting from a more severe winter season encountered in the 2013 first quarter, which created a more challenging operating environment compared to a mild winter season experienced in the 2012 first quarter.

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Production taxes and other expenses increased $21.7 million, or 43%, to $72.4 million during the three months ended March 31, 2013 compared to the three months ended March 31, 2012 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes. Production taxes and other expenses include charges for marketing, gathering, dehydration and compression fees primarily related to natural gas sales in the Oklahoma Woodford and North Dakota Bakken areas of $7.6 million and $5.4 million for the three months ended March 31, 2013 and 2012, respectively. The increase in other charges is primarily due to the increase in natural gas sales volumes in 2013. Production taxes, excluding other charges, as a percentage of crude oil and natural gas revenues were 8.2% for the three months ended March 31, 2013 compared to 8.1% for the three months ended March 31, 2012. Production taxes are generally based on the wellhead values of production and vary by state. 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 reverts to the statutory rate. North Dakota, which is our most active area of operations, has production tax rates of up to 11.5% of crude oil revenues. Our overall production tax rate is expected to increase as we continue to grow our operations in North Dakota and as production tax incentives we currently receive for horizontal wells reach the end of their incentive periods.

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

	Three months ended March 31,	
$/Boe	**2013**	**2012**
Production expenses	$ 5.70	$ 5.18
Production taxes and other expenses	6.69	6.56
Production expenses, production taxes and other expenses	$ 12.39	$ 11.74

Exploration Expenses. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. The following table shows the components of exploration expenses for the periods presented.

	Three months ended March 31,	
(in thousands)	**2013**	**2012**
Geological and geophysical costs	$ 7,553	$ 4,063
Dry hole costs	2,261	88
Exploration expenses	$ 9,814	$ 4,151

Geological and geophysical costs increased $3.5 million for the three months ended March 31, 2013 due to changes in the timing and amount of acquisitions of seismic data between periods. Dry hole charges recognized in 2013 were primarily concentrated in a non-Woodford area in our South region.

Depreciation, Depletion, Amortization and Accretion (DD&A). Total DD&A increased $64.2 million, or 43%, in the first quarter of 2013 compared to the first quarter of 2012 primarily due to a 41% increase in production volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Three months ended March 31,	
$/Boe	**2013**	**2012**
Crude oil and natural gas	$ 19.43	$ 18.92
Other equipment	0.23	0.30
Asset retirement obligation accretion	0.06	0.10
Depreciation, depletion, amortization and accretion	$ 19.72	$ 19.32

The increase in DD&A per Boe is partially the result of a gradual shift in our production base from our historic base of the Red River units in the Cedar Hills field to newer production bases in the Bakken and Oklahoma Woodford plays. The producing properties in our newer areas typically carry higher DD&A rates due to the higher costs of developing reserves in those areas compared to our older, more mature properties.

Property Impairments. Property impairments increased in the three months ended March 31, 2013 by $10.2 million to $40.1 million compared to $29.9 million for the three months ended March 31, 2012.

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Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually insignificant non-producing properties are amortized on an aggregate basis based on our estimated experience of successful drilling and the average holding period. Impairments of non-producing properties increased $10.2 million during the three months ended March 31, 2013 to $40.1 million compared to $29.9 million for the three months ended March 31, 2012. The increase resulted from a larger base of amortizable costs in the current period coupled with a larger amount of undeveloped leasehold acreage expected to expire compared to the prior period. We currently have no individually significant non-producing properties that are assessed for impairment on a property-by-property basis.

We evaluate 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 value using discounted cash flows. No impairment provisions for proved properties were recognized for the three months ended March 31, 2013 or 2012. For those periods, future cash flows were determined to be in excess of cost basis, therefore no impairment was necessary.

General and Administrative Expenses. General and administrative expenses (G&A) increased $8.8 million to $33.8 million for the three months ended March 31, 2013 from $25.0 million for the comparable period in 2012. G&A expenses include non-cash charges for equity compensation of $9.2 million and $5.5 million for the three months ended March 31, 2013 and 2012, respectively. The increase in equity compensation in 2013 resulted from larger grants of restricted stock being made throughout 2012 and into 2013 due to employee growth along with an increase in our grant date stock prices, which resulted in increased expense recognition in the first quarter of 2013 compared to the first quarter of 2012. G&A expenses excluding equity compensation increased $5.1 million for the three months ended March 31, 2013 compared to the same period in 2012. The increase was due in part to an increase in personnel costs and office-related expenses associated with our rapid growth. Over the past year, we have grown from 656 total employees in March 2012 to 769 total employees in March 2013, a 17% increase.

The previously announced relocation of our corporate headquarters from Enid, Oklahoma to Oklahoma City was completed during 2012; however, ancillary relocation-related costs continue to be incurred. For the three months ended March 31, 2013, we recognized $0.7 million of costs associated with our relocation compared to $1.7 million for the three months ended March 31, 2012.

The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

	Three months ended March 31,	
$/Boe	**2013**	**2012**
General and administrative expenses	$ 2.20	$ 2.29
Non-cash equity compensation	0.85	0.71
Corporate relocation expenses	0.06	0.23
Total general and administrative expenses	$ 3.11	$ 3.23

Interest Expense. Interest expense increased $23.2 million, or 96%, to $47.5 million for the three months ended March 31, 2013 compared to $24.3 million for the three months ended March 31, 2012 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the three months ended March 31, 2013 was approximately $3.7 billion with a weighted average interest rate of 4.9% compared to a weighted average outstanding long-term debt balance of $1.6 billion and a weighted average interest rate of 5.2% for the comparable period in 2012. The increase in outstanding debt resulted from borrowings incurred last year to fund capital expenditures and property acquisitions. On March 8, 2012 and August 16, 2012, we issued $800 million and $1.2 billion, respectively, of 5% Senior Notes due 2022 (the 2022 Notes) and used the net proceeds from those issuances to repay credit facility borrowings, to fund a portion of our 2012 capital budget and for general corporate purposes. Interest expense recognized for the 2022 Notes in the first quarter of 2013 amounted to $24.7 million compared to $2.5 million in the first quarter of 2012. We expect interest expense to further increase as a result of our April 2013 issuance of $1.5 billion of 2023 Notes.

Our weighted average outstanding credit facility balance increased to $815.9 million for the first quarter of 2013 compared to $484.5 million for the first quarter of 2012. The weighted average interest rate on our credit facility borrowings was 1.9% for the first quarter of 2013 compared to 2.5% for the same period in 2012. At March 31, 2013, we had approximately $1.04 billion of outstanding borrowings on our credit facility, which was subsequently paid off using a portion of the proceeds from our issuance of the 2023 Notes in April 2013. We had $595.0 million of outstanding borrowings on our credit facility at December 31, 2012. The increase in credit facility borrowings in the 2013 first quarter resulted from borrowings being incurred to fund our capital program.

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Income Taxes. We recorded income tax expense for the three months ended March 31, 2013 of $82.6 million compared to $43.0 million for the three months ended March 31, 2012. We provided for income taxes at a combined federal and state tax rate of approximately 37% and 38% for the three months ended March 31, 2013 and 2012, respectively, 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 debt and equity securities. As of March 31, 2013, we had $58.5 million of cash and cash equivalents and $460.2 million of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. Subsequent to March 31, 2013, our liquidity has improved as a result of the repayment of our credit facility borrowings outstanding at that date using proceeds from our April 2013 issuance of $1.5 billion of 2023 Notes. As of April 30, 2013, we had $1.5 billion of borrowing availability on our credit facility with no borrowings outstanding.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities was $458.1 million and $364.9 million for the three months ended March 31, 2013 and 2012, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues driven by higher sales volumes coupled with lower realized losses on derivatives, which were partially offset by increases in production expenses, production taxes, general and administrative expenses, and other expenses associated with the growth of our operations.

Cash flows used in investing activities

During the three months ended March 31, 2013 and 2012, we had cash flows used in investing activities (excluding asset sales) of $873.5 million and $1,079.9 million, respectively, related to our capital program, inclusive of dry hole costs. The decrease in cash flows used in investing activities in 2013 was primarily due to fewer capital expenditures being incurred for property acquisitions compared to the prior year first quarter. In the first quarter of 2012 we executed a transaction to acquire properties in North Dakota for $276 million, with no transactions of that size occurring in the first quarter of 2013.

The use of cash for capital expenditures during the three months ended March 31, 2012 was partially offset by proceeds received from asset dispositions. Proceeds from the sale of assets amounted to $84.8 million for the three months ended March 31, 2012, primarily related to our February 2012 disposition of certain Wyoming properties for proceeds of $84.4 million. No significant asset dispositions occurred during the three months ended March 31, 2013.

Cash flows from financing activities

Net cash provided by financing activities for the three months ended March 31, 2013 was $437.9 million, primarily resulting from $440.0 million of borrowings being incurred under our credit facility during the period to fund our capital program. Net cash provided by financing activities of $619.3 million for the three months ended March 31, 2012 was the result of receiving $787.0 million of net proceeds from our March 2012 issuance of $800 million of 5% Senior Notes due 2022, along with $22.0 million received from a 10-year term loan executed in February 2012, partially offset by net repayments of $182.0 million on our credit facility.

Future Sources of Financing

Although we cannot provide any assurance, assuming sustained strength in crude oil prices and successful implementation of our business strategy, we believe funds from operating cash flows, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, 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 for the next 12 months. We may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms.

Based on our planned production growth and derivative contracts we have in place to limit the downside risk of adverse price movements associated with the forecasted sale of future production, we currently anticipate we will be able to generate or obtain funds sufficient to meet our short-term and long-term cash requirements. We intend to finance future capital expenditures primarily through cash flows from operations and through borrowings under our credit facility, but we may also issue debt or equity securities or sell assets. The issuance of additional debt requires a portion of our cash flows from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock.

Revolving credit facility

We have a credit facility which has aggregate lender commitments totaling $1.5 billion and a borrowing base of $3.25 billion, subject to semi-annual redetermination. The most recent borrowing base redetermination was completed in December 2012, whereby the lenders approved an increase in the borrowing base from $2.75 billion to $3.25 billion. The aggregate commitment level may be increased from time to time (provided no default exists) up to the lesser of $2.5 billion or the borrowing base then in effect. Borrowings under the credit facility bear interest at a rate per annum equal to the London Interbank Offered Rate (LIBOR) for one, two, three or six months, as elected by us, plus a margin ranging from 150 to 250 basis points, depending on the percentage of the borrowing base utilized, or the lead bank s reference rate (prime) plus a margin ranging from 50 to 150 basis points.

The commitments under our credit facility, which matures on July 1, 2015, are from a syndicate of 14 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. If one or more lenders cannot fund its commitment, we would not have the full availability of the $1.5 billion commitment.

We had $1,035.0 million of outstanding borrowings and $460.2 million of borrowing availability (after considering outstanding borrowings and letters of credit) on our credit facility at March 31, 2013. The outstanding borrowings at March 31, 2013 include borrowings incurred in late 2012 to fund a portion of our December 2012 acquisition of North Dakota Bakken properties for $663.3 million, along with additional borrowings incurred during the three months ended March 31, 2013 to fund our 2013 capital program.

On April 5, 2013, we issued $1.5 billion of 2023 Notes and received net proceeds of approximately $1.48 billion after deducting the initial purchasers fees. The net proceeds were used to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of approximately $1.04 billion. At April 30, 2013, we had no outstanding borrowings and approximately $1.5 billion of borrowing availability under our credit facility.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. Our credit facility also contains requirements that we maintain a current ratio of not less than 1.0 to 1.0 and a ratio of total funded debt to EBITDAX of no greater than 4.0 to 1.0. As defined by our credit facility, the current ratio represents our ratio of current assets to current liabilities, inclusive of available borrowing capacity under the credit facility and exclusive of current balances associated with derivative contracts and asset retirement obligations. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided subsequently under the caption *Non-GAAP Financial Measures*. The total funded debt to EBITDAX ratio represents the sum of outstanding borrowings and letters of credit under our revolving credit facility plus our note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with these covenants at March 31, 2013 and expect to maintain compliance for at least the next 12 months. A violation of these covenants in the future could result in a default under our credit facility and such event could result in an acceleration of other outstanding indebtedness. In the event of such default, the lenders under our credit facility could elect to terminate their commitments thereunder, cease making further loans, and could declare all outstanding amounts, if any, to be due and payable. If we had any outstanding borrowings under our credit facility and such indebtedness were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. We do not believe the restrictive covenants are reasonably likely to limit our ability to undertake additional debt or equity financing to a material extent.

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 or increase their commitments to the borrowing base amount. We expect the next borrowing base redetermination to occur in the second quarter of 2013. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base.

If we are unable to access funding on acceptable terms when needed, 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.

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Proceeds from issuance of long-term debt

As discussed above, we used a portion of the $1.48 billion of net proceeds from our April 5, 2013 issuance of the 2023 Notes to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of approximately $1.04 billion. We expect to use the remaining net proceeds from the issuance of approximately $0.4 billion to fund a portion of our 2013 capital budget and for general corporate purposes.

Derivative activities

As part of our risk management program, we hedge a portion of our anticipated future crude oil and natural gas production 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 adequate funds are available for our capital program. Our decision on the quantity and price at which we choose to hedge our future production is based in part on our view of current and future market conditions and our desire to have the cash flows needed to fund the development of our inventory of undeveloped crude oil and natural gas reserves in conjunction with our growth strategy. Refer to *Note 4. Derivative Instruments* in *Notes to Unaudited Condensed Consolidated Financial Statements* for further discussion of the accounting applicable to our derivative instruments, a summary of open contracts at March 31, 2013 and the estimated fair value of those contracts as of that date.

Future Capital Requirements

Senior note maturities

The following table summarizes the maturity dates, semi-annual interest payment dates, and optional redemption periods related to our outstanding senior note obligations, including the 2023 Notes issued on April 5, 2013.

	2019 Notes	2020 Notes	2021 Notes	2022 Notes	2023 Notes
Maturity date	Oct. 1, 2019	Oct. 1, 2020	April 1, 2021	Sept. 15, 2022	April 15, 2023
Interest payment dates	April 1, Oct. 1	April 1, Oct. 1	April 1, Oct. 1	March 15, Sept. 15	April 15, Oct. 15
Call premium redemption period (1)	Oct. 1, 2014	Oct. 1, 2015	April 1, 2016	March 15, 2017	n/a
Make-whole redemption period (2)	Oct. 1, 2014	Oct. 1, 2015	April 1, 2016	March 15, 2017	January 15, 2023
Equity offering redemption period (3)		Oct. 1, 2013	April 1, 2014	March 15, 2015	n/a

(1) On or after these dates, we have the option to redeem all or a portion of our senior notes at the decreasing redemption prices specified in the respective senior note indentures (together, the Indentures) plus any accrued and unpaid interest to the date of redemption.
(2) At any time prior to these dates, we have the option to redeem all or a portion of our senior notes at the make-whole redemption prices or amounts specified in the Indentures plus any accrued and unpaid interest to the date of redemption.
(3) At any time prior to these dates, we may redeem up to 35% of the principal amount of our senior notes under certain circumstances with the net cash proceeds from one or more equity offerings at the redemption prices specified in the Indentures plus any accrued and unpaid interest to the date of redemption. The optional redemption period for the 2019 Notes using equity offering proceeds expired on October 1, 2012.

Currently, we have no plans or intentions of exercising an early redemption option on the senior notes. Our senior 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 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 March 31, 2013 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. Two of our subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have insignificant assets with no current value and no operations, fully and unconditionally guarantee the senior notes. Our other subsidiary, 20 Broadway Associates LLC, the value of whose assets and operations are minor, does not guarantee the senior notes.

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Capital expenditures

We evaluate opportunities to purchase or sell crude oil and natural gas properties and expect to 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 October 2012, we announced a new five-year growth plan to triple our production and proved reserves from year-end 2012 to year-end 2017. Our capital expenditures budget for 2013 is $3.6 billion excluding acquisitions, which is expected to be allocated as follows.

	Amount *in millions*
Exploration and development drilling	$ 3,155
Land costs	220
Capital facilities, workovers and re-completions	175
Buildings, vehicles, computers and other equipment	30
Seismic	20
Total	$ 3,600

During the three months ended March 31, 2013, we participated in the completion of 196 gross (80.0 net) wells and invested a total of $920.9 million, including unbudgeted acquisitions of $22.0 million, in our capital program (including $5.3 million of seismic costs and $42.2 million of capital costs associated with increased accruals for capital expenditures). Our 2013 year-to-date capital expenditures were as follows.

	Amount *in millions*
Exploration and development drilling	$ 791.9
Land costs	78.3
Capital facilities, workovers and re-completions	10.9
Buildings, vehicles, computers and other equipment	12.5
Seismic	5.3
Capital expenditures, excluding acquisitions	$ 898.9
Acquisitions of producing properties	3.3
Acquisitions of non-producing properties	18.7
Total acquisitions	$22.0
Total capital expenditures	$ 920.9

Although we cannot provide any assurance, assuming sustained strength in crude oil prices and successful implementation of our business strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe funds from operating cash flows, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to fund the remainder of our 2013 capital program; however, we may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms. 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, unbudgeted acquisitions, actual drilling results, the availability of drilling rigs and other services and equipment, changes in commodity prices, and regulatory, technological and competitive developments. We expect to continue participating as a buyer of properties when and if we have the ability to increase our position in strategic plays at favorable terms.

Commitments

Following is a discussion of various future commitments of the Company as of March 31, 2013. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments As of March 31, 2013, we had drilling rig contracts with various terms extending through August 2014. These contracts were entered into in the ordinary 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 condensed consolidated balance sheets. Future drilling commitments as of March 31, 2013 total approximately $82 million, of which $65 million is expected to be incurred in the remainder of 2013 and $17 million in 2014. We expect to continue to enter into additional drilling rig contracts to help mitigate the risk of experiencing equipment shortages and rising costs that could delay our drilling projects or cause us to incur expenditures not provided for in our capital budget.

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Fracturing and well stimulation service agreement We have an agreement with a third party whereby the third party will 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 term of the agreement ends in September 2013. Pursuant to the take-or-pay provisions, we will pay a fixed rate per day for a minimum number of days per calendar quarter regardless of whether the services have been provided. The agreement also stipulates we will bear the cost of certain products and materials used. Future commitments remaining at March 31, 2013 amount to approximately $11 million, which is expected to be incurred up through September 2013. Since the inception of this agreement, we have been using the services more than the minimum number of days each quarter.

Pipeline transportation commitments We have entered into firm transportation commitments to guarantee pipeline access capacity totaling 15,000 barrels of crude oil per day on operational pipelines in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The commitments, which have 5-year terms extending as far as November 2017, require us to pay varying per-barrel transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of March 31, 2013 under the operational pipeline transportation arrangements amount to approximately $52 million, of which $10 million is expected to be incurred in the remainder of 2013, $13 million in 2014, $13 million in 2015, $10 million in 2016 and $6 million in 2017.

Further, we are a party to additional 5-year firm transportation commitments for future pipeline projects being considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require significant additional construction efforts by our counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.0 billion at March 31, 2013, representing aggregate transportation charges expected to be incurred over the 5-year terms of the arrangements assuming the proposed pipeline projects are completed and become operational. The timing of the commencement of pipeline operations is not known due to uncertainties involving matters such as regulatory approvals, resolution of legal and environmental disputes, construction progress and the ultimate probability of pipeline completion. Accordingly, the timing of our obligations under these non-operational arrangements cannot be predicted with certainty and may not be incurred on a ratable basis over a calendar year or may not be incurred at all. Although timing is uncertain, our obligations under these arrangements are not expected to begin until at least 2014.

Rail transportation commitments We have entered into firm transportation commitments to guarantee capacity on rail transportation facilities in order to reduce the impact of possible curtailments that may arise due to limited transportation capacity. The rail commitments have various terms extending through December 2015 and require us to pay varying per-barrel transportation charges on volumes ranging from 2,500 to 10,000 barrels of crude oil per day regardless of the amount of rail capacity used. Future commitments remaining as of March 31, 2013 under the rail transportation arrangements amount to approximately $43 million, of which $26 million is expected to be incurred in the remainder of 2013, $10 million in 2014 and $7 million in 2015.

Our pipeline and rail transportation commitments are for crude oil production in the North region where we allocate a significant portion of our capital expenditures. We are not committed under these contracts to deliver fixed and determinable quantities of crude oil or natural gas in the future.

We believe our cash flows from operations, our remaining cash balance, and amounts available under our credit facility, including our ability to increase our borrowing capacity thereunder, will be sufficient to satisfy the above commitments.

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our Form 10-K for the year ended December 31, 2012.

Recent Accounting Pronouncements Not Yet Adopted

We are monitoring the joint standard-setting efforts of the FASB and International Accounting Standards Board. There are a number of pending accounting standards being targeted for completion in 2013 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, and accounting for financial instruments. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact these standards will have, if any, on our financial position, results of operations or cash flows.

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Non-GAAP Financial Measures

We use a variety of financial and operational measures to assess our performance. Among these measures is EBITDAX. EBITDAX represents earnings before interest expense, income taxes, depreciation, depletion, amortization and accretion, property impairments, exploration expenses, non-cash gains and losses resulting from the requirements of accounting for derivatives, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP.

Management believes EBITDAX is useful because it allows us 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 and operating cash flows 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 operating 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 EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total funded debt to EBITDAX ratio of no greater than 4.0 to 1.0 on a rolling four-quarter basis. This ratio represents the sum of outstanding borrowings and letters of credit under our credit facility plus our note payable and senior note obligations, divided by total EBITDAX for the most recent four quarters. We were in compliance with this covenant at March 31, 2013. A violation of this covenant in the future could result in a default under our credit facility and such event could result in an acceleration of other outstanding indebtedness. In the event of such default, the lenders under our credit facility could elect to terminate their commitments thereunder, cease making further loans, and could declare all outstanding amounts, if any, to be due and payable. If we had any outstanding borrowings under our credit facility and such indebtedness were to be accelerated, our assets may not be sufficient to repay in full such indebtedness. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us.

The following table provides a reconciliation of our net income to EBITDAX for the periods presented.

in thousands	Three months ended March 31, 2013	2012
Net income	$ 140,627	$ 69,094
Interest expense	47,475	24,278
Provision for income taxes	82,590	43,000
Depreciation, depletion, amortization and accretion	213,678	149,455
Property impairments	40,081	29,907
Exploration expenses	9,814	4,151
Impact from derivative instruments:		
Total loss on derivatives, net	84,831	169,057
Total realized loss (cash flow) on derivatives, net	(6,810)	(39,925)
Non-cash loss on derivatives, net	78,021	129,132
Non-cash equity compensation	9,242	5,515
EBITDAX	$ 621,528	$ 454,532

The following table provides a reconciliation of our net cash provided by operating activities to EBITDAX for the periods presented.

in thousands	Three months ended March 31, 2013	2012
Net cash provided by operating activities	$ 458,111	$ 364,944
Current income tax provision		2,150

Interest expense	47,475	24,278
Exploration expenses, excluding dry hole costs	7,553	4,063
Gain on sale of assets, net	136	49,627
Other, net	(3,176)	(1,646)
Changes in assets and liabilities	111,429	11,116
EBITDAX	$ 621,528	$ 454,532

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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 natural gas production. Pricing for crude oil and natural gas 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 prices. Based on our average daily production for the three months ended March 31, 2013, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $314 million for each $10.00 per barrel change in crude oil prices and $78 million for each $1.00 per Mcf change in natural gas prices.

To reduce price risk caused by these market fluctuations, we periodically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps ensure we have adequate funds available for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While hedging limits the downside risk of adverse price movements, it also limits future revenues from upward price movements.

Changes in commodity futures price strips during the three months ended March 31, 2013 had an overall negative impact on the fair value of our derivative instruments. For the three months ended March 31, 2013, we realized a net loss on derivatives of $6.8 million and reported an unrealized non-cash mark-to-market loss on derivatives of $78.0 million. The fair value of our derivative instruments at March 31, 2013 was a net liability of $42.6 million. The mark-to-market net liability relates to derivative instruments with various terms that are scheduled to be realized over the period from April 2013 through December 2015. Over this period, actual realized derivative settlements may differ significantly, either positively or negatively, from the unrealized mark-to-market valuation at March 31, 2013. An assumed increase in the forward commodity prices used in the March 31, 2013 valuation of our derivative instruments of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would increase our net derivative liability to approximately $570 million at March 31, 2013. Conversely, an assumed decrease in forward commodity prices of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would change our derivative valuation to a net asset of approximately $468 million at March 31, 2013.

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 ($558.3 million in receivables at March 31, 2013), our joint interest receivables ($357.2 million at March 31, 2013), and counterparty credit risk associated with our derivative instrument receivables ($36.4 million at March 31, 2013).

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 which own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases included in units 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 generally 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 $42.6 million at March 31, 2013, 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.

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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. Substantially all of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our credit facility.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to any variable-rate borrowings we may have outstanding from time to time under our 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 had no outstanding borrowings under our credit facility at April 30, 2013.

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 March 31, 2013. 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 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 March 31, 2013, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Controls and Procedures

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

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PART II. Other Information

ITEM 1. Legal Proceedings

During the three months ended March 31, 2013 there have been no material changes with respect to the legal proceedings previously disclosed in our 2012 Form 10-K that was filed with the SEC on February 28, 2013. See *Note 7. Commitments and Contingencies* in *Notes to Unaudited Condensed Consolidated Financial Statements* included elsewhere in this report.

ITEM 1A. Risk Factors

There have been no material changes in our risk factors from those disclosed in our 2012 Form 10-K.

In addition to the information set forth in this Form 10-Q, you should carefully consider the risk factors discussed in *Part I, Item 1A. Risk Factors* in our 2012 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 2012 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

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

(a) Recent Sales of Unregistered Securities Not applicable.

(b) Use of Proceeds Not applicable.

(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers The following table provides information about purchases of equity securities registered by the Company pursuant to Section 12 of the Exchange Act during the quarter ended March 31, 2013:

Period	Total number of shares purchased (1)	Average price paid per share (2)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or program (3)
January 1, 2013 to January 31, 2013	1,174	$ 76.05		
February 1, 2013 to February 28, 2013	16,682	$ 83.88		
March 1, 2013 to March 31, 2013		$		
Total	17,856	$ 83.37		

(1) In connection with restricted stock grants under the Continental Resources, Inc. 2005 Long-Term Incentive Plan (2005 Plan), we adopted a policy that enables employees to surrender shares to cover their tax liability. 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 the restrictions lapsed on such shares.

(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 vesting of restrictions on shares under the 2005 Plan.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

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ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

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

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SIGNATURE

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

CONTINENTAL RESOURCES, INC.

Date: May 8, 2013

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

(Duly Authorized Officer and Principal Financial Officer)

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Index to Exhibits

3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed February 24, 2012 as Exhibit 3.1 to the Company s 2011 Form 10-K (Commission File No. 001-32886) and incorporated herein by reference.
3.2	Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.1 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed November 6, 2012 and incorporated herein by reference.
4.1	Indenture dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed April 11, 2013 and incorporated herein by reference.
4.2	Registration Rights Agreement dated as of April 5, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated as the representative of the several initial purchasers, filed as Exhibit 4.2 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed April 11, 2013 and incorporated herein by reference.
10.1*	Description of cash bonus plan adopted on February 22, 2013.
10.2	Purchase Agreement dated as of April 2, 2013 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated as representative of the several initial purchasers filed as Exhibit 10.1 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed April 3, 2013 and incorporated herein by reference.
10.3	Amendment No. 2 dated April 3, 2013 to the Seventh Amended and Restated Credit Agreement dated June 30, 2010, among Continental Resources, Inc., as borrower, Banner Pipeline Company L.L.C. and CLR Asset Holdings, LLC as guarantors, Union Bank, N.A., as administrative agent and issuing lender, and the other lenders party thereto filed as Exhibit 10.1 to the Company s Current Report on Form 8-K (Commission File No. 001-32886) filed April 5, 2013 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
Management contract or compensatory plan or arrangement filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.