CONTINENTAL RESOURCES, INC
Form 10-Q
November 05, 2014
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2014

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 (State or other jurisdiction of incorporation or organization)	73-0767549 (I.R.S. Employer Identification No.)
20 N. Broadway, Oklahoma City, Oklahoma (Address of principal executive offices)	73102 (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

372,213,798 shares of our $0.01 par value common stock were outstanding on October 31, 2014.

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

Glossary of Crude Oil and Natural Gas Terms

The terms defined in this section may be 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 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.

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

"gross acres" or "gross wells" Refers to the total acres or wells in which a working interest is owned.

"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.

"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.

"net acres" or "net wells" Refers to the sum of the fractional working interests owned in gross acres or gross wells.

"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 completion 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 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 may lack readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. 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, and generally require horizontal drilling, fracture stimulation treatments or other special recovery processes in order to achieve economic production.
"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.

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,” “g and 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, if any, our Annual Report on Form 10-K for the year ended December 31, 2013, registration statements filed from time to time with the Securities and Exchange Commission ("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 crude oil and natural gas 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 or other 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.

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 and transportation infrastructure, environmental risks, drilling and other operating risks, lack of availability and security of computer-based systems, 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, if any, our Annual Report on Form 10-K for the year ended December 31, 2013, 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.

PART I. Financial Information
ITEM 1. Financial Statements
Continental Resources, Inc. and Subsidiaries
Condensed Consolidated Balance Sheets

In thousands, except par values and share data	September 30, 2014 (Unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$152,290	$28,482
Receivables:		
Crude oil and natural gas sales	671,769	643,498
Affiliated parties	15,066	13,107
Joint interest and other, net	507,038	349,579
Derivative assets	143,268	3,616
Inventories	82,564	54,440
Deferred and prepaid taxes	11,393	44,337
Prepaid expenses and other	15,488	10,207
Total current assets	1,598,876	1,147,266
Net property and equipment, based on successful efforts method of accounting	12,993,789	10,721,272
Net debt issuance costs and other	88,420	72,644
Noncurrent derivative assets	31,002	—
Total assets	$14,712,087	$11,941,182
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable trade	$1,201,082	$885,289
Revenues and royalties payable	323,277	291,772
Payables to affiliated parties	10,473	5,436
Accrued liabilities and other	267,623	198,113
Derivative liabilities	—	90,535
Current portion of long-term debt	2,062	2,011
Total current liabilities	1,804,517	1,473,156
Long-term debt, net of current portion	5,831,860	4,713,821
Other noncurrent liabilities:		
Deferred income tax liabilities	2,155,442	1,736,812
Asset retirement obligations, net of current portion	62,331	54,353
Noncurrent derivative liabilities	—	7,829
Other noncurrent liabilities	9,727	2,093
Total other noncurrent liabilities	2,227,500	1,801,087
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; 372,046,368 shares issued and outstanding at September 30, 2014; 371,317,318 shares issued and outstanding at December 31, 2013	3,720	3,713
Additional paid-in capital	1,281,970	1,250,178
Retained earnings	3,562,520	2,699,227

Total shareholders’ equity	4,848,210	3,953,118
Total liabilities and shareholders’ equity	$14,712,087	$11,941,182

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

In thousands, except per share data	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Revenues				
Crude oil and natural gas sales	$1,138,460	$981,170	$3,223,605	$2,595,416
Crude oil and natural gas sales to affiliates	21,821	28,666	77,094	74,843
Gain (loss) on derivative instruments, net	473,999	(203,774)	171,801	(89,548)
Crude oil and natural gas service operations	11,048	8,825	31,418	29,876
Total revenues	1,645,328	814,887	3,503,918	2,610,587
Operating costs and expenses				
Production expenses	95,700	66,790	255,911	201,250
Production and other expenses to affiliates	1,674	260	2,870	1,055
Production taxes and other expenses	97,399	84,334	272,726	223,718
Exploration expenses	13,514	8,173	29,532	29,138
Crude oil and natural gas service operations	4,337	6,654	18,390	22,567
Depreciation, depletion, amortization and accretion	363,677	244,721	963,409	695,189
Property impairments	85,561	42,167	223,085	161,960
General and administrative expenses	43,980	34,070	134,435	103,761
(Gain) loss on sale of assets, net	(5,411)	(325)	952	(112)
Total operating costs and expenses	700,431	486,844	1,901,310	1,438,526
Income from operations	944,897	328,043	1,602,608	1,172,061
Other income (expense):				
Interest expense	(73,912)	(62,756)	(209,728)	(171,609)
Loss on extinguishment of debt	(24,517)	—	(24,517)	—
Other	393	584	1,945	1,765
	(98,036)	(62,172)	(232,300)	(169,844)
Income before income taxes	846,861	265,871	1,370,308	1,002,217
Provision for income taxes	313,340	98,373	507,015	370,822
Net income	$533,521	$167,498	$863,293	$631,395
Basic net income per share	$1.45	$0.45	$2.34	$1.72
Diluted net income per share	$1.44	$0.45	$2.33	$1.71

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

In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Retained earnings	Total shareholders’ equity
Balance at December 31, 2013	371,317,318	$3,713	$1,250,178	$2,699,227	$3,953,118
Net income (unaudited)	—	—	—	863,293	863,293
Stock-based compensation (unaudited)	—	—	39,409	—	39,409
Restricted stock:					
Granted (unaudited)	1,251,264	12	—	—	12
Repurchased and canceled (unaudited)	(117,314)	(1)	(7,617)	—	(7,618)
Forfeited (unaudited)	(404,900)	(4)	—	—	(4)
Balance at September 30, 2014 (unaudited)	372,046,368	$3,720	$1,281,970	$3,562,520	$4,848,210

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

Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Cash Flows

In thousands	Nine months ended September 30, 2014	2013
Cash flows from operating activities		
Net income	$863,293	$631,395
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	970,273	694,729
Property impairments	223,085	161,960
Non-cash (gain) loss on derivatives, net	(269,018)	37,638
Stock-based compensation	39,419	29,460
Provision for deferred income taxes	504,737	360,599
Dry hole costs	9,142	9,180
(Gain) loss on sale of assets, net	952	(112)
Loss on extinguishment of debt	24,517	—
Other, net	5,986	4,308
Changes in assets and liabilities:		
Accounts receivable	(192,178)	(178,171)
Inventories	(28,124)	(8,529)
Prepaid expenses and other	(7,017)	(11,118)
Accounts payable trade	82,297	151,266
Revenues and royalties payable	32,500	46,611
Accrued liabilities and other	16,645	41,791
Other noncurrent assets and liabilities	1,342	7,446
Net cash provided by operating activities	2,277,851	1,978,453
Cash flows from investing activities		
Exploration and development	(3,255,327)	(2,767,448)
Purchase of producing crude oil and natural gas properties	(48,305)	(12,404)
Purchase of other property and equipment	(51,974)	(41,942)
Proceeds from sale of assets	129,346	22,406
Net cash used in investing activities	(3,226,260)	(2,799,388)
Cash flows from financing activities		
Credit facility borrowings	1,105,000	470,000
Repayment of credit facility	(1,380,000)	(1,065,000)
Proceeds from issuance of Senior Notes	1,681,834	1,479,375
Redemption of Senior Notes	(300,000)	—
Premium on redemption of Senior Notes	(17,497)	—
Repayment of other debt	(1,503)	(1,457)
Debt issuance costs	(7,999)	(2,263)
Repurchase of equity grants	(7,618)	(3,942)
Net cash provided by financing activities	1,072,217	876,713
Net change in cash and cash equivalents	123,808	55,778
Cash and cash equivalents at beginning of period	28,482	35,729
Cash and cash equivalents at end of period	$152,290	$91,507

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
Continental Resources, Inc. (the "Company") was originally formed in 1967 and is incorporated under the laws of the State of Oklahoma. The Company'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 various plays in the South Central Oklahoma Oil Province ("SCOOP"), Northwest Cana, and Arkoma areas of Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River with no current drilling or production operations.
The Company's operations are geographically concentrated in the North region, with that region comprising approximately 74% of the Company's crude oil and natural gas production and approximately 83% of its crude oil and natural gas revenues for the nine months ended September 30, 2014. Our principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. The remainder of the Company's crude oil and natural gas production and revenue is derived from the South region, primarily from producing properties in the SCOOP play in south-central Oklahoma.
The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the nine months ended September 30, 2014, crude oil accounted for approximately 70% of the Company's total production and approximately 85% 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 the Company and its subsidiaries, all of which are 100% owned, after all significant intercompany accounts and transactions have been eliminated upon consolidation.
On August 18, 2014, the Company's Board of Directors declared a 2-for-1 stock split of the Company's common stock to be effected in the form of a stock dividend. The stock dividend was distributed on September 10, 2014 to shareholders of record as of September 3, 2014. All previously reported common stock and earnings per share amounts have been retroactively adjusted in the accompanying financial statements and related notes to reflect the stock split.
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, 2013 ("2013 Form 10-K"), which includes a summary of the Company's significant accounting policies and other disclosures.
The condensed consolidated financial statements as of September 30, 2014 and for the three and nine month periods ended September 30, 2014 and 2013 are unaudited. The condensed consolidated balance sheet as of December 31, 2013 was derived from the audited balance sheet included in the 2013 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 and estimation of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting periods. Actual results may 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 an entire year.

Continental Resources, Inc. and Subsidiaries
Notes to Unaudited Condensed Consolidated Financial Statements

Inventories

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

In thousands	September 30, 2014	December 31, 2013
Tubular goods and equipment	$13,586	$11,139
Crude oil	68,978	43,301
Total	$82,564	$54,440

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	September 30, 2014	December 31, 2013
Crude oil line fill and tank requirements	941	370
Temporarily stored crude oil	196	344
Total	1,137	714

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, which are calculated using the treasury stock method. The following table presents the calculation of basic and diluted weighted average shares outstanding and net income per share for the three and nine months ended September 30, 2014 and 2013. Weighted average shares and net income per share amounts for the three and nine months ended September 30, 2013 have been retroactively adjusted to reflect the Company's 2-for-1 stock split occurring in September 2014.

	Three months ended September 30,		Nine months ended September 30,	
In thousands, except per share data	2014	2013	2014	2013
Income (numerator):				
Net income - basic and diluted	$533,521	$167,498	$863,293	$631,395
Weighted average shares (denominator):				
Weighted average shares - basic	368,814	368,139	368,740	368,072
Non-vested restricted stock	1,714	1,622	1,892	1,485
Weighted average shares - diluted	370,528	369,761	370,632	369,557
Net income per share:				
Basic	$1.45	$0.45	$2.34	$1.72
Diluted	$1.44	$0.45	$2.33	$1.71

New accounting pronouncement

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers (Topic 606). The standard’s core principle is that an entity shall recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard generally requires an entity to identify performance obligations in its contracts, estimate the amount of variable consideration to be received in the transaction price, allocate the transaction price to each separate performance obligation, and recognize revenue as obligations are satisfied. The standard will be effective for annual and interim periods beginning after December 15, 2016. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Company is evaluating the impact of the provisions of ASU 2014-09; however, the standard is not expected to have a material effect on the Company’s financial position, results of operations or cash flows.

Reclassifications

Certain prior year amounts have been reclassified to conform to the current year presentation. In the prior year, the Company presented charges related to natural gas transportation and processing under the caption “Production taxes and other expenses” or “Production and other expenses to affiliates” in the unaudited condensed consolidated statements of income. Such charges, which totaled $8.9 million for the three months ended September 30, 2013, including transactions with an affiliate totaling $1.2 million, and $24.2 million for the nine months ended September 30, 2013, including transactions with an affiliate totaling $3.5 million, have been reclassified to be netted within “Crude oil and natural gas sales” or "Crude oil and natural gas sales to affiliates", as applicable, in order to conform to the current year presentation. The reclassifications had no impact on previously reported operating income, net income, current assets, total assets, current liabilities, total liabilities, stockholders' equity 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.

	Nine months ended September 30,	
In thousands	2014	2013
Supplemental cash flow information:		
Cash paid for interest	$173,057	$139,023
Cash paid for income taxes	4,012	23,413
Cash received for income tax refunds	5	173
Non-cash investing activities:		
Increase in accrued capital expenditures	235,431	69,767
Asset retirement obligation additions and revisions, net	6,232	5,043

Note 4. Derivative Instruments

The Company recognizes 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 changes in fair value in the unaudited condensed consolidated statements of income under the caption “Gain (loss) on derivative instruments, net.”

The Company may utilize swap and collar derivative contracts to economically 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.

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At September 30, 2014, the Company had outstanding derivative contracts as set forth in the tables below. Subsequent to September 30, 2014, the Company settled substantially all of its outstanding crude oil derivative contracts prior to their contractual maturities as discussed below under the heading Derivative liquidations.

Crude Oil - NYMEX WTI - as of September 30, 2014		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	Bbls	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
October 2014 - December 2014						
Swaps - WTI	3,335,000	$96.22				
January 2015 - December 2015						
Collars - WTI	4,380,000		$87.00	$87.00	$95.85 - $103.75	$98.36

Crude Oil - ICE Brent - as of September 30, 2014		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	Bbls	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
October 2014 - December 2014						
Swaps - ICE Brent	4,508,000	$103.29				
Collars - ICE Brent	552,000		$90.00 - $95.00	$90.83	$104.70 - $108.85	$107.13
January 2015 - December 2015						
Swaps - ICE Brent	24,637,500	$100.85				
Collars - ICE Brent	730,000		$95.00	$95.00	$107.40	$107.40
January 2016 - December 2016						
Collars - ICE Brent	1,464,000		$90.00	$90.00	$107.70	$107.70

Natural Gas - Henry Hub - as of September 30, 2014		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	MMBtus	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
October 2014 - December 2014						
Swaps - Henry Hub	30,820,000	$4.20				
January 2015 - December 2015						
Swaps - Henry Hub	24,500,000	$4.27				
Collars - Henry Hub	29,200,000		$3.50 - $3.75	$3.69	$4.89 - $5.48	$5.04
January 2016 - December 2016						
Swaps - Henry Hub	4,550,000	$4.27				

Derivative liquidations
In October 2014, following a decrease in crude oil commodity prices and related increase in the fair value of derivative assets, substantially all of the Company's crude oil derivative contracts outstanding as of September 30, 2014 were settled prior to the expiration of their contractual maturities, resulting in the receipt of cash proceeds

totaling approximately $433 million which will be reflected in fourth quarter results. No natural gas derivative contracts in place as of September 30, 2014 were liquidated in October 2014.

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The tables below set forth the Company's remaining crude oil derivative contracts in place as of October 31, 2014 after settlement of matured October 2014 contracts and the liquidations referred to above.

Crude Oil - NYMEX WTI - as of October 31, 2014		Ceilings	
Period and Type of Contract	Bbls	Range	Weighted Average Price
January 2015 - December 2015			
Written call options - WTI (1)	4,380,000	$95.85 - $103.75	$98.36

Crude Oil - ICE Brent - as of October 31, 2014		Floors		Ceilings	
Period and Type of Contract	Bbls	Range	Weighted Average Price	Range	Weighted Average Price
November 2014 - December 2014					
Collars - ICE Brent	366,000	$90.00 - $95.00	$90.83	$104.70 - $108.85	$107.13
January 2015 - December 2015					
Written call options - ICE Brent (1)	730,000			$107.40	$107.40
January 2016 - December 2016					
Written call options - ICE Brent (1)	1,464,000			$107.70	$107.70

(1) The written call options represent the ceiling positions remaining from the Company's crude oil collar contracts. The floor positions of the collars were liquidated. For these written call options, 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 below the ceiling price.

Derivative gains and losses

The following table presents cash settlements on matured derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented. Cash receipts and payments below reflect the gain or loss on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continue to be held at period end and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the period.

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2014	2013	2014	2013
Cash received (paid) on derivatives:				
Crude oil fixed price swaps	$(4,126)	$(39,298)	$(77,148)	$(46,810)
Crude oil collars	(233)	(15,081)	(2,270)	(14,701)
Natural gas fixed price swaps	4,549	14,030	(17,799)	9,601
Cash received (paid) on derivatives, net	190	(40,349)	(97,217)	(51,910)
Non-cash gain (loss) on derivatives:				
Crude oil fixed price swaps	416,637	(146,782)	228,845	(38,234)
Crude oil collars	27,386	(13,243)	28,300	(11,037)
Natural gas fixed price swaps	25,851	(3,400)	7,944	11,633
Natural gas collars	3,935	—	3,929	—
Non-cash gain (loss) on derivatives, net	473,809	(163,425)	269,018	(37,638)
Gain (loss) on derivative instruments, net	$473,999	$(203,774)	$171,801	$(89,548)

Balance sheet offsetting of derivative assets and liabilities

All of the Company's derivative contracts are recorded at 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.

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The following table presents 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.

In thousands	September 30, 2014	December 31, 2013
Commodity derivative assets:		
Gross amounts of recognized assets	$174,478	$4,213
Gross amounts offset on balance sheet	(208)	(597)
Net amounts of assets on balance sheet	174,270	3,616
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	—	(125,709)
Gross amounts offset on balance sheet	—	27,345
Net amounts of liabilities on balance sheet	$—	$(98,364)

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

In thousands	September 30, 2014	December 31, 2013
Derivative assets	$143,268	$3,616
Noncurrent derivative assets	31,002	—
Net amounts of assets on balance sheet	174,270	3,616
Derivative liabilities	—	(90,535)
Noncurrent derivative liabilities	—	(7,829)
Net amounts of liabilities on balance sheet	—	(98,364)
Total derivative assets (liabilities), net (1)	$174,270	$(94,748)

(1) As discussed above, subsequent to September 30, 2014 the Company settled substantially all of its outstanding crude oil derivative contracts prior to their contractual maturities. As of October 31, 2014, the fair value of the Company's remaining derivative contracts was a net asset of approximately $20 million, representing a net asset of $27 million associated with natural gas derivatives partially offset by a net liability of $7 million associated with remaining crude oil derivatives.

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.

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Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Company's derivative instruments are reported at fair value on a recurring basis. 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 of fair value for each of its derivative positions is compared to the counterparty valuation for reasonableness.

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 September 30, 2014 and December 31, 2013.

	Fair value measurements at September 30, 2014 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$151,896	$—	$151,896
Collars	—	22,374	—	22,374
Total	$—	$174,270	$—	$174,270

	Fair value measurements at December 31, 2013 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$(84,893)	$—	$(84,893)
Collars	—	(9,855)	—	(9,855)
Total	$—	$(94,748)	$—	$(94,748)

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 2018 (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.

During the periods ended September 30, 2014 and September 30, 2013, the Company determined the carrying amounts of certain proved properties were not recoverable from future cash flows and, therefore, were impaired. Impairments of proved properties amounted to $38.0 million and $69.3 million for the three and nine months ended September 30, 2014, respectively, which primarily reflect fair value adjustments made for certain properties in non-core areas of the South region. The impaired properties were written down to their estimated fair value totaling approximately $15.4 million. Impairment provisions for proved properties totaled $39.6 million for the nine months ended September 30, 2013, which were recognized in the second quarter of that period and primarily reflected uneconomic results for certain wells drilled in the Niobrara play in Colorado and Wyoming. Those impaired properties were written down to their estimated fair value totaling approximately $22.2 million as of September 30, 2013.

Certain unproved crude oil and natural gas properties were impaired during the three and nine months ended September 30, 2014 and 2013, 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 September 30,		Nine months ended September 30,	
In thousands	2014	2013	2014	2013
Proved property impairments	$38,046	$—	$69,337	$39,635
Unproved property impairments	47,515	42,167	153,748	122,325
Total	$85,561	$42,167	$223,085	$161,960

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.

	September 30, 2014		December 31, 2013	
In thousands	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Credit facility	$—	$—	$275,000	$275,000
Note payable	16,967	15,186	18,470	16,500
8.25% Senior Notes due 2019 (1)	—	—	298,305	327,800
7.375% Senior Notes due 2020	198,809	220,940	198,695	223,700
7.125% Senior Notes due 2021	400,000	443,240	400,000	450,300
5% Senior Notes due 2022	2,023,568	2,106,000	2,025,362	2,063,300
4.5% Senior Notes due 2023	1,500,000	1,560,000	1,500,000	1,519,400
3.8% Senior Notes due 2024	996,548	1,003,900	—	—
4.9% Senior Notes due 2044	698,030	728,350	—	—
Total debt	$5,833,922	$6,077,616	$4,715,832	$4,876,000

(1) These senior notes were redeemed in July 2014. See Note 6. Long-Term Debt for further discussion.

The fair value of credit facility borrowings approximates 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.

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The fair values of the 8.25% Senior Notes due 2019 (“2019 Notes”), the 7.375% Senior Notes due 2020 (“2020 Notes”), the 7.125% Senior Notes due 2021 (“2021 Notes”), the 5% Senior Notes due 2022 (“2022 Notes”), the 4.5% Senior Notes due 2023 ("2023 Notes"), the 3.8% Senior Notes due 2024 ("2024 Notes"), and the 4.9% Senior Notes due 2044 ("2044 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 at September 30, 2014 and December 31, 2013:

In thousands	September 30, 2014	December 31, 2013
Credit facility	$—	$275,000
Note payable	16,967	18,470
8.25% Senior Notes due 2019 (1)	—	298,305
7.375% Senior Notes due 2020 (2)	198,809	198,695
7.125% Senior Notes due 2021 (3)	400,000	400,000
5% Senior Notes due 2022 (4)	2,023,568	2,025,362
4.5% Senior Notes due 2023 (3)	1,500,000	1,500,000
3.8% Senior Notes due 2024 (5)	996,548	—
4.9% Senior Notes due 2044 (6)	698,030	—
Total debt	5,833,922	4,715,832
Less: Current portion of long-term debt	(2,062)	(2,011)
Long-term debt, net of current portion	$5,831,860	$4,713,821

(1) The carrying amount is net of an unamortized discount of $1.7 million at December 31, 2013. The 2019 Notes were redeemed in July 2014 as discussed further below.

(2) The carrying amount is net of unamortized discounts of $1.2 million and $1.3 million at September 30, 2014 and December 31, 2013, respectively.

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

(4) The carrying amount includes an unamortized premium of $23.6 million and $25.4 million at September 30, 2014 and December 31, 2013, respectively.

(5) The carrying amount is net of an unamortized discount of $3.5 million at September 30, 2014.

(6) The carrying amount is net of an unamortized discount of $2.0 million at September 30, 2014.

Credit Facility

The Company has an unsecured credit facility, maturing on May 16, 2019, with aggregate commitments totaling $1.75 billion, which may be increased up to $4.0 billion upon agreement between the Company and participating lenders. The Company had no outstanding borrowings and approximately $1.75 billion of unused commitments on its credit facility at September 30, 2014. Borrowings under the credit facility bear interest at market-based interest rates plus a margin that is based on the terms of the borrowing and the credit ratings assigned to the Company's senior unsecured debt. The Company incurs commitment fees based on currently assigned credit ratings of 0.225% 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 net debt to capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (total debt less cash and cash equivalents) divided by the sum of net debt plus total shareholders’ equity. The Company was in compliance with this covenant at September 30, 2014.

Senior Notes

On May 19, 2014, the Company issued $1.0 billion of new 3.8% Senior Notes due 2024 and $700 million of new 4.9% Senior Notes due 2044 and received total net proceeds of approximately $1.68 billion after deducting the initial purchasers' fees. The Company used a portion of the net proceeds from the offerings to repay all borrowings then outstanding under its credit facility, which had a balance prior to payoff of $1.01 billion, and to finance the redemption of its 2019 Notes as discussed below. The remaining net proceeds are being used to fund a portion of the Company's 2014 capital program and for general corporate purposes.

On July 11, 2014, the Company redeemed its 2019 Notes using a portion of the proceeds from its May 2014 issuances of 2024 Notes and 2044 Notes. The 2019 Notes were redeemed for $317.5 million, representing a make-whole amount calculated in accordance with the terms of the 2019 Notes and related indenture. The Company recognized a pre-tax loss of $24.5 million related to the redemption, which includes the make-whole premium and the write-off of deferred financing costs and unaccreted debt discount and is reflected under the caption “Loss on extinguishment of debt" in the unaudited condensed consolidated statements of income for the three and nine months ended September 30, 2014.

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 September 30, 2014.

	2020 Notes	2021 Notes	2022 Notes	2023 Notes	2024 Notes	2044 Notes
Maturity date	Oct 1, 2020	April 1, 2021	Sep 15, 2022	April 15, 2023	June 1, 2024	June 1, 2044
Interest payment dates	April 1, Oct. 1	April 1, Oct. 1	March 15, Sept. 15	April 15, Oct. 15	June 1, Dec. 1	June 1, Dec.1
Call premium redemption period (1)	Oct 1, 2015	April 1, 2016	March 15, 2017	—	—	—
Make-whole redemption period (2)	Oct 1, 2015	April 1, 2016	March 15, 2017	Jan 15, 2023	Mar 1, 2024	Dec 1, 2043
Equity offering redemption period (3)	—	—	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.

(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 or amounts specified in the Indentures plus any accrued and unpaid interest to the date of redemption.

(3) At any time prior to this date, the Company may redeem up to 35% of the principal amount of its 2022 Notes under certain circumstances with the net cash proceeds from one or more equity offerings at the redemption price specified in the indenture for the 2022 Notes plus any accrued and unpaid interest to the date of redemption.

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

The indentures governing the Company's senior notes contain covenants that, among others, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale-leaseback transactions, and consolidate, merge or transfer certain assets. The senior note covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at September 30, 2014. Two of the Company’s subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have no material assets or operations, fully and unconditionally guarantee the senior notes. The Company’s other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

Note Payable

In February 2012, 20 Broadway Associates LLC, a 100% 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 $2.1 million is reflected as a current liability under the caption “Current portion of long-term debt” in the condensed consolidated balance sheets as of September 30, 2014.

Note 7. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of September 30, 2014. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.
Drilling commitments – As of September 30, 2014, the Company had drilling rig contracts with various terms extending through July 2018. 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 September 30, 2014

total approximately $675 million, of which $66 million is expected to be incurred in the remainder of 2014, $246 million in 2015, $213 million in 2016, $122 million in 2017, and $28 million in 2018.

Pipeline transportation commitments – The Company has entered into firm transportation commitments to guarantee pipeline access capacity on operational crude oil and natural gas pipelines in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The commitments, which have varying terms extending as far as 2025, require the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of September 30, 2014 under the operational pipeline transportation arrangements amount to approximately $1.0 billion, of which $40 million is expected to be incurred in the remainder of 2014, $181 million in 2015, $186 million in 2016, $180 million in 2017, $175 million in 2018, and $241 million thereafter.

Further, the Company is a party to an additional firm transportation commitment for a future crude oil pipeline project being considered for development that is not yet operational. The project requires the granting of regulatory approvals and requires additional construction efforts by the counterparty before being completed. Future commitments under the non-operational arrangement total approximately $260 million at September 30, 2014. This commitment represents aggregate transportation charges expected to be incurred over the five year term beginning when the proposed pipeline project is completed and becomes operational. The exact 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 this non-operational arrangement 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.

The Company’s pipeline commitments are for production primarily 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.

Cost sharing commitment – The Company has entered into an arrangement to share certain costs associated with a local utility company's construction and installation of electrical infrastructure that will provide service to parts of North Dakota where the Company operates. This arrangement extends through January 2016 and requires the Company to make scheduled periodic payments based on the projected total cost of the project and the progress of construction. Future commitments under the arrangement as of September 30, 2014 total approximately $13 million, of which $3 million is expected to be incurred in the remainder of 2014, $8 million in 2015, and $2 million in 2016.

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 $165 million which may increase with the passage of time, 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 including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims and other 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 September 30, 2014 and

December 31, 2013, the Company had recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $2.9 million and $1.7 million, respectively, for various matters, none of which are believed to be individually significant.

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

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Note 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”) and 2013 Long-Term Incentive Plan ("2013 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 September 30,		Nine months ended September 30,	
In thousands	2014	2013	2014	2013
Non-cash equity compensation	$13,402	$10,462	$39,419	$29,460

In May 2013, the Company adopted the 2013 Plan and reserved a maximum of 19,680,072 shares of common stock (adjusted for stock split) that may be issued pursuant to the plan. The 2013 Plan replaced the Company's 2005 Plan as the instrument used to grant long-term incentive awards and no further awards will be granted under the 2005 Plan. However, restricted stock awards granted under the 2005 Plan prior to the adoption of the 2013 Plan will remain outstanding in accordance with their terms. As of September 30, 2014, the Company had a maximum of 18,220,078 shares of restricted stock (adjusted for stock split) available to grant to officers, directors and select employees under the 2013 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 and, except as otherwise provided under the 2013 Plan or agreement relevant to a given award, includes the right to vote the restricted stock or 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 shares outstanding for the nine months ended September 30, 2014 is presented below. Share amounts and related grant-date fair values have been retroactively adjusted to reflect the Company's 2-for-1 stock split occurring in September 2014.

	Number of non-vested shares		Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2013	2,714,312		$37.50
Granted	1,251,264		61.69
Vested	(365,498	)	36.53
Forfeited	(404,900	)	44.04
Non-vested restricted shares outstanding at September 30, 2014	3,195,178		$46.25

The grant date fair value of restricted stock represents the closing market price 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 nine months ended September 30, 2014 at the vesting date was approximately $23.6 million. As of September 30, 2014, there was approximately $78 million of unrecognized compensation expense related to non-vested restricted stock. This expense is expected to be recognized ratably over a weighted average period of 1.3 years.

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, 2013. 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 in 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, 2013, 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 various plays in the South Central Oklahoma Oil Province ("SCOOP"), Northwest Cana, and Arkoma areas of Oklahoma. The East region is comprised of undeveloped leasehold acreage east of the Mississippi River with no current drilling or production operations.

Our operations are geographically concentrated in the North region, with that region comprising approximately 74% of our crude oil and natural gas production and approximately 83% of our crude oil and natural gas revenues for the nine months ended September 30, 2014. Our principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. The remainder of our crude oil and natural gas production and revenue is derived from the South region, primarily from producing properties in the SCOOP play in south-central Oklahoma.

We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas. 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 three dimensional seismic, horizontal drilling, geosteering technologies, advanced completion technologies (e.g., fracture stimulation) and enhanced recovery technologies provide the means to economically develop and produce crude oil and natural gas reserves from unconventional formations. We expect growth in our revenues and operating income will primarily depend on commodity prices and our ability to increase our reserves and related crude oil and natural gas production.

2014 Highlights

Production, revenues and operating cash flows

For the third quarter of 2014, our crude oil and natural gas production averaged 182,335 Boe per day, representing a 9% increase over average daily production of 167,953 Boe per day for the second quarter of 2014 and a 29% increase over average daily production of 141,873 Boe per day for the third quarter of 2013. Crude oil and natural gas production averaged 167,696 Boe per day for the nine months ended September 30, 2014, a 26% increase over average daily production of 133,110 Boe per day for the comparable 2013 period. Crude oil represented 70% of our total production for both the three and nine months ended September 30, 2014, compared to 71% for both the three and nine months ended September 30, 2013.

The increase in 2014 production was primarily driven by higher production from our properties in the Bakken field and SCOOP play due to the continued success of our drilling programs in those areas.

Our total Bakken production averaged 121,604 Boe per day for the third quarter of 2014, a 12% increase over the second quarter of 2014 and 29% higher than the third quarter of 2013. Total Bakken production averaged 109,300 Boe per day for the nine months ended September 30, 2014, a 26% increase over the nine months ended September 30, 2013.

Production in the SCOOP play averaged 36,346 Boe per day for the third quarter of 2014, a 6% increase over the second quarter of 2014 and 81% higher than the third quarter of 2013. SCOOP production averaged 33,350 Boe per day for the nine months ended September 30, 2014, an increase of 93% over the nine months ended September 30, 2013.

Crude oil and natural gas revenues for the third quarter of 2014 increased 15% to $1.16 billion due to a 30% increase in sales volumes partially offset by an 11% decrease in realized commodity prices when compared to the third quarter of 2013. For the nine months ended September 30, 2014, crude oil and natural gas revenues totaled $3.30 billion, a 24% increase from the comparable 2013 period due to a 25% increase in sales volumes partially offset by a 1% decrease in realized commodity prices. Crude oil represented 87% and 85% of our total crude oil and natural gas revenues for the three and nine months ended September 30, 2014, respectively, compared to 89% for both the three and nine months ended September 30, 2013. The decreased percentage of crude oil revenues resulted from a significant increase in SCOOP revenues as a percentage of our total revenues over the past year. Our properties in SCOOP produce a higher concentration of liquids-rich natural gas compared to certain other operating areas such as the Bakken.

Cash flows from operating activities for the nine months ended September 30, 2014 were $2.28 billion, a 15% increase from $1.98 billion provided by our operating activities during the comparable 2013 period. The increased operating cash flows in 2014 were primarily due to higher crude oil and natural gas revenues driven by higher sales volumes, partially offset by an increase in cash losses on matured derivatives and higher production expenses, production taxes, general and administrative expenses, interest expense and other expenses associated with the growth of our operations over the past year.

Capital expenditures

Our capital expenditures budget for 2014 is $4.55 billion, excluding acquisitions. For the nine months ended September 30, 2014, we invested approximately $3.42 billion in our capital program, excluding $179.8 million of unbudgeted acquisitions. Our 2014 capital program is focused primarily on increased exploration and development in the Bakken field and the SCOOP play.

Stock split

On August 18, 2014, our Board of Directors declared a 2-for-1 stock split of our common stock to be effected in the form of a stock dividend. The stock dividend was distributed on September 10, 2014 to shareholders of record as of September 3, 2014. All previously reported common stock and earnings per share amounts have been retroactively adjusted throughout this report to reflect the stock split.

Redemption of senior notes

On June 3, 2014, we announced our intention to redeem our $300 million of 8.25% Senior Notes due 2019. The 2019 Notes were fully redeemed on July 11, 2014 for $317.5 million. We recognized a pre-tax loss of $24.5 million related to the redemption, which is reflected under the caption “Loss on extinguishment of debt" in the unaudited condensed consolidated statements of income for the three and nine months ended September 30, 2014.

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).

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The following table contains financial and operating highlights for the periods presented. Average sales prices exclude any effect of derivative transactions. Per-unit expenses have been calculated using sales volumes.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Average daily production:				
Crude oil (Bbl per day)	127,788	100,684	116,954	94,315
Natural gas (Mcf per day)	327,287	247,135	304,453	232,769
Crude oil equivalents (Boe per day)	182,335	141,873	167,696	133,110
Average sales prices:				
Crude oil ($/Bbl)	$85.49	$98.02	$89.02	$91.89
Natural gas ($/Mcf)	$5.10	$4.84	$5.80	$4.78
Crude oil equivalents ($/Boe)	$69.08	$77.86	$72.52	$73.46
Crude oil sales price differential to NYMEX ($/Bbl)	$(11.77)	$(7.80)	$(10.60)	$(6.51)
Natural gas sales price premium to NYMEX ($/Mcf)	$1.04	$1.26	$1.28	$1.09
Production expenses ($/Boe)	$5.80	$5.17	$5.69	$5.57
Production taxes (% of oil and gas revenues)	8.3%	8.3%	8.1%	8.3%
DD&A ($/Boe)	$21.65	$18.87	$21.17	$19.13
General and administrative expenses ($/Boe)	$1.82	$1.81	$2.08	$2.00
Non-cash equity compensation ($/Boe)	$0.80	$0.81	$0.87	$0.81
Net income (in thousands)	$533,521	$167,498	$863,293	$631,395
Diluted net income per share	$1.44	$0.45	$2.33	$1.71
EBITDAX (in thousands) (1)	$947,635	$797,575	$2,590,980	$2,127,211

(1) 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, non-cash equity compensation expense, and losses on extinguishment of debt. 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.

Three months ended September 30, 2014 compared to the three months ended September 30, 2013

Results of Operations

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

	Three months ended September 30,	
In thousands, except sales price data	2014	2013
Crude oil and natural gas sales	$1,160,281	$1,009,836
Gain (loss) on derivative instruments, net	473,999	(203,774)
Crude oil and natural gas service operations	11,048	8,825
Total revenues	1,645,328	814,887
Operating costs and expenses	(700,431)	(486,844)
Other expenses, net (1)	(98,036)	(62,172)
Income before income taxes	846,861	265,871
Provision for income taxes	(313,340)	(98,373)
Net income	$533,521	$167,498
Production volumes:		
Crude oil (MBbl) (2)	11,756	9,263
Natural gas (MMcf)	30,110	22,736
Crude oil equivalents (MBoe)	16,775	13,052
Sales volumes:		
Crude oil (MBbl) (2)	11,777	9,180
Natural gas (MMcf)	30,110	22,736
Crude oil equivalents (MBoe)	16,796	12,969
Average sales prices: (3)		
Crude oil ($/Bbl)	$85.49	$98.02
Natural gas ($/Mcf)	5.10	4.84
Crude oil equivalents ($/Boe)	69.08	77.86

(1) Amount includes a loss on extinguishment of debt of $24.5 million for the three months ended September 30, 2014 related to the July 2014 redemption of our 8.25% Senior Notes due 2019.

(2) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or marketing disruptions 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 21 MBbls more than crude oil production for the three months ended September 30, 2014 and 83 MBbls less than crude oil production for the three months ended September 30, 2013.

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

Production

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

	Three months ended September 30,				Volume increase	Volume percent increase
	2014		2013			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	11,756	70 %	9,263	71 %	2,493	27 %
Natural gas (MMcf)	30,110	30 %	22,736	29 %	7,374	32 %
Total (MBoe)	16,775	100 %	13,052	100 %	3,723	29 %

	Three months ended September 30,				Volume increase	Volume percent increase
	2014		2013			
	MBoe	Percent	MBoe	Percent		
North Region	12,519	75 %	10,084	77 %	2,435	24 %
South Region	4,256	25 %	2,968	23 %	1,288	43 %
Total	16,775	100 %	13,052	100 %	3,723	29 %

Crude oil production volumes increased 2,493 MBbls, or 27%, for the three months ended September 30, 2014 compared to the three months ended September 30, 2013. Production increases in the Bakken field and SCOOP play contributed incremental production volumes in the 2014 third quarter of 2,587 MBbls, a 33% increase over production in these areas for the third quarter of 2013. Production growth in these areas is primarily due to increased drilling and completion activity resulting from our drilling program.

Natural gas production volumes increased 7,374 MMcf, or 32%, during the three months ended September 30, 2014 compared to the same period in 2013. Natural gas production in the Bakken field increased 1,832 MMcf, or 22%, for the three months ended September 30, 2014 compared to the same period in 2013 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in the play. Natural gas production in the SCOOP play increased 6,592 MMcf, or 84%, due to additional wells being completed and producing in the three months ended September 30, 2014 compared to the same period in 2013. These increases were partially offset by decreases in production from various areas in our North and South regions due to a combination of natural declines in production and reduced drilling activity.

Revenues

Our total revenues consist of sales of crude oil and natural gas, gains and losses resulting from 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 September 30, 2014 were $1,160.3 million, a 15% increase from sales of $1,009.8 million for the same period in 2013. Our sales volumes increased 3,827 MBoe, or 30%, over the comparable period in 2013 primarily due to the success of our drilling programs in the Bakken field and SCOOP play.

At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or marketing disruptions 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 21 MBbls more than crude oil production for the three months ended September 30, 2014. An increase in crude oil line fill requirements and related reduction in sales volumes in the 2014 third quarter associated with new pipelines put into service was more than offset by the sale of crude oil during the quarter that was temporarily stored in inventory at June 30, 2014.

Our realized sales price per Boe decreased $8.78 to $69.08 for the three months ended September 30, 2014 from $77.86 for the three months ended September 30, 2013. This decrease primarily reflects lower prices realized in connection with reduced market prices for crude oil compared to the prior year.

The differential between NYMEX West Texas Intermediate ("WTI") calendar month average crude oil prices and our realized crude oil sales price per barrel for the third quarter of 2014 was $11.77 compared to $7.80 for the third quarter of 2013. We expect volatility in crude oil prices and differentials to continue.

Derivatives. We have entered into a number of derivative contracts, 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 changes in fair value in the unaudited condensed consolidated statements of income under the caption “Gain (loss) on derivative instruments, net”, which is a component of total revenues.

Subsequent to September 30, 2014, substantially all of our crude oil derivative contracts were settled prior to the expiration of their contractual maturities. See Note 4. Derivative Instruments in Notes to Unaudited Condensed Consolidated Financial Statements for further discussion including a summary of remaining derivative contracts in place as of October 31, 2014.

Changes in commodity prices during the third quarter of 2014 had a positive impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $474.0 million for the three months ended September 30, 2014. We expect our revenues may continue to be impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in commodity prices.

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The following table presents the impact on total revenues related to cash settlements on matured derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented. Cash receipts and payments below reflect the gain or loss on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continue to be held at period end and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured during the period.

	Three months ended September 30,	
In thousands	2014	2013
Cash received (paid) on derivatives:		
Crude oil derivatives	$(4,359)	$(54,379)
Natural gas derivatives	4,549	14,030
Cash received (paid) on derivatives, net	190	(40,349)
Non-cash gain (loss) on derivatives:		
Crude oil derivatives	444,023	(160,025)
Natural gas derivatives	29,786	(3,400)
Non-cash gain (loss) on derivatives, net	473,809	(163,425)
Gain (loss) on derivative instruments, net	$473,999	$(203,774)

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 45% to $97.4 million for the three months ended September 30, 2014 from $67.0 million for the three months ended September 30, 2013. This increase was primarily the result of an increase in the number of producing wells. Production expense per Boe was $5.80 for the three months ended September 30, 2014 compared to $5.17 per Boe for the three months ended September 30, 2013.

Production taxes and other expenses increased $13.1 million, or 16%, to $97.4 million for the three months ended September 30, 2014 compared to $84.3 million for the three months ended September 30, 2013 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes. Production taxes as a percentage of crude oil and natural gas revenues were 8.3% for both the three months ended September 30, 2014 and 2013. 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, certain horizontal wells are taxed at a lower rate during their initial months of production which subsequently increases after a specified period of time or when specified production volumes are achieved.

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

	Three months ended September 30,	
In thousands	2014	2013
Geological and geophysical costs	$8,755	$7,055
Exploratory dry hole costs	4,759	1,118
Exploration expenses	$13,514	$8,173

Depreciation, Depletion, Amortization and Accretion (“DD&A”). Total DD&A increased $119.0 million, or 49%, to $363.7 million for the third quarter of 2014 compared to $244.7 million for the third quarter of 2013 primarily due to a 30% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Three months ended September 30,	
$/Boe	2014	2013
Crude oil and natural gas	$21.26	$18.58
Other equipment	0.34	0.24
Asset retirement obligation accretion	0.05	0.05
Depreciation, depletion, amortization and accretion	$21.65	$18.87

The increase in DD&A per Boe for the third quarter of 2014 resulted from an increased use of enhanced completion methods that increased completed well costs. Additionally, certain exploratory wells, primarily in non-core areas, resulted in more expensive reserve additions. These factors contributed to an increase in DD&A on a per-Boe basis over the prior period.

Property Impairments. Impairments of non-producing properties increased $5.3 million for the three months ended September 30, 2014 to $47.5 million compared to $42.2 million for the three months ended September 30, 2013. The increase primarily resulted from a larger base of amortizable costs in the current period coupled with higher rates of amortization in certain areas resulting from changes in management's estimates of undeveloped properties not expected to be developed before lease expiration.

Impairment provisions for proved properties totaled $38.0 million for the three months ended September 30, 2014, primarily reflecting fair value adjustments made for certain properties in non-core areas of our South region. No impairment provisions for proved properties were recognized for the three months ended September 30, 2013.

General and Administrative Expenses. General and administrative ("G&A") expenses increased $9.9 million, or 29%, to $44.0 million for the three months ended September 30, 2014 from $34.1 million for the comparable period in 2013. G&A expenses include non-cash charges for equity compensation of $13.4 million and $10.5 million for the three months ended September 30, 2014 and 2013, respectively. The increase in equity compensation expense in 2014 resulted from a higher value of restricted stock grants being made in 2013 and 2014 due to employee growth, which resulted in increased expense recognition in the third quarter of 2014 compared to the third quarter of 2013.

G&A expenses other than equity compensation increased $7.0 million, or 30%, for the three months ended September 30, 2014 compared to the same period in 2013. The increase was primarily due to an increase in personnel costs and office-related expenses associated with our growth. Over the past year, our Company has grown from having 883 total employees at September 30, 2013 to 1,124 total employees at September 30, 2014, a 27% increase.

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

	Three months ended September 30,	
$/Boe	2014	2013
General and administrative expenses	$1.82	$1.81
Non-cash equity compensation	0.80	0.81
Corporate relocation expenses	—	0.01
Total general and administrative expenses	$2.62	$2.63

Interest Expense. Interest expense increased $11.1 million, or 18%, to $73.9 million for the three months ended September 30, 2014 compared to $62.8 million for the three months ended September 30, 2013 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the third quarter of 2014 was approximately $5.9 billion with a weighted average interest rate of 4.8% compared to a weighted average outstanding long-term debt balance of $4.4 billion and a weighted average interest rate of 5.3% for the comparable period in 2013. The increase in outstanding debt resulted from higher borrowings being incurred to fund our increased capital budget.

Income Taxes. We recorded income tax expense for the three months ended September 30, 2014 of $313.3 million compared to $98.4 million for the three months ended September 30, 2013. We provided for income taxes at a combined federal and state tax rate of approximately 37% for the third quarter of both 2014 and 2013 after taking into account permanent taxable differences.

Nine months ended September 30, 2014 compared to the nine months ended September 30, 2013

Results of Operations

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

	Nine months ended September 30,	
In thousands, except sales price data	2014	2013
Crude oil and natural gas sales	$3,300,699	$2,670,259
Gain (loss) on derivative instruments, net	171,801	(89,548)
Crude oil and natural gas service operations	31,418	29,876
Total revenues	3,503,918	2,610,587
Operating costs and expenses	(1,901,310)	(1,438,526)
Other expenses, net (1)	(232,300)	(169,844)
Income before income taxes	1,370,308	1,002,217
Provision for income taxes	(507,015)	(370,822)
Net income	$863,293	$631,395
Production volumes:		
Crude oil (MBbl) (2)	31,928	25,748
Natural gas (MMcf)	83,116	63,546
Crude oil equivalents (MBoe)	45,781	36,339
Sales volumes:		
Crude oil (MBbl) (2)	31,664	25,757
Natural gas (MMcf)	83,116	63,546
Crude oil equivalents (MBoe)	45,516	36,348
Average sales prices: (3)		
Crude oil ($/Bbl)	$89.02	$91.89
Natural gas ($/Mcf)	5.80	4.78
Crude oil equivalents ($/Boe)	72.52	73.46

(1) Amount includes a loss on extinguishment of debt of $24.5 million for the nine months ended September 30, 2014 related to the July 2014 redemption of our 8.25% Senior Notes due 2019.

(2) At various times we have stored crude oil due to pipeline line fill requirements, low commodity prices, or marketing disruptions 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 264 MBbls less than crude oil production for the nine months ended September 30, 2014 and 9 MBbls more than crude oil production for the nine months ended September 30, 2013.

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

Production

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

	Nine months ended September 30,				Volume increase	Volume percent increase
	2014		2013			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	31,928	70%	25,748	71%	6,180	24%
Natural gas (MMcf)	83,116	30%	63,546	29%	19,570	31%
Total (MBoe)	45,781	100%	36,339	100%	9,442	26%

	Nine months ended September 30,				Volume increase	Volume percent increase
	2014		2013			
	MBoe	Percent	MBoe	Percent		
North Region	33,890	74%	28,037	77%	5,853	21%
South Region	11,891	26%	8,302	23%	3,589	43%

Total	45,781	100 %	36,339	100 %	9,442	26 %

Crude oil production volumes increased 6,180 MBbls, or 24%, during the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. Production increases in the Bakken field and SCOOP play contributed incremental production volumes in 2014 of 6,528 MBbls, a 30% increase over production in these areas for the comparable period in 2013. Production growth in these areas is primarily due to increased drilling and completion activity resulting from our drilling program. These increases were partially offset by decreases in production from various areas in our North and South regions due to a combination of natural declines in production and reduced drilling activity.

Natural gas production volumes increased 19,570 MMcf, or 31%, during the nine months ended September 30, 2014 compared to the same period in 2013. Natural gas production in the Bakken field increased 4,386 MMcf, or 20%, for the nine months ended September 30, 2014 compared to the same period in 2013 due to new wells being completed and gas from existing wells being connected to natural gas processing plants in the play. Natural gas production in the SCOOP play increased 20,011 MMcf, or 100%, due to additional wells being completed and producing in the nine months ended September 30, 2014 compared to the same period in 2013. These increases were partially offset by decreases in production from various areas in our North and South regions due to a combination of natural declines in production and reduced drilling activity.

Revenues

Our total revenues consist of sales of crude oil and natural gas, gains and losses resulting from 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 nine months ended September 30, 2014 were $3,300.7 million, a 24% increase from sales of $2,670.3 million for the same period in 2013. Our sales volumes increased 9,168 MBoe, or 25%, over the comparable period in 2013 primarily due to the success of our drilling programs in the Bakken field and SCOOP play. Changes in transportation availability, pipeline line fill requirements, and initial tank fill at storage facilities resulted in an increase in crude oil stored in inventory in 2014, primarily in the first half of the year, which caused crude oil sales volumes to be lower than crude oil production by 264 MBbls.

Our realized price per Boe decreased $0.94, or 1%, to $72.52 for the nine months ended September 30, 2014 from $73.46 for the nine months ended September 30, 2013. The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel for the nine months ended September 30, 2014 was $10.60 per barrel compared to $6.51 for the nine months ended September 30, 2013. We expect volatility in crude oil prices and differentials to continue.

Derivatives. Changes in commodity futures price strips during the nine months ended September 30, 2014 had a positive impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $171.8 million for the nine months ended September 30, 2014. We expect our revenues may continue to be impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in commodity prices.

Subsequent to September 30, 2014, substantially all of our crude oil derivative contracts were settled prior to the expiration of their contractual maturities. See Note 4. Derivative Instruments in Notes to Unaudited Condensed Consolidated Financial Statements for further discussion including a summary of remaining derivative contracts in place as of October 31, 2014.

The following table presents the impact on total revenues related to cash and non-cash gains and losses on derivative instruments for the periods presented.

	Nine months ended September 30,			
In thousands	2014		2013	
Cash received (paid) on derivatives:				
Crude oil derivatives	$(79,418	)	$(61,511	)
Natural gas derivatives	(17,799	)	9,601	
Cash paid on derivatives, net	(97,217	)	(51,910	)
Non-cash gain (loss) on derivatives:				
Crude oil derivatives	257,145		(49,271	)
Natural gas derivatives	11,873		11,633	

Non-cash gain (loss) on derivatives, net	269,018	(37,638)
Gain (loss) on derivative instruments, net	$171,801	$(89,548)

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 28% to $258.8 million during the nine months ended September 30, 2014 from $202.3 million during the nine months ended September 30, 2013. This increase is primarily the result of an increase in the number of producing wells. Production expense per Boe was $5.69 for the nine months ended September 30, 2014 compared to $5.57 per Boe for the nine months ended September 30, 2013.

Production taxes and other expenses increased $49.0 million, or 22%, to $272.7 million during the nine months ended September 30, 2014 compared to $223.7 million for the nine months ended September 30, 2013 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes. Production taxes as a percentage of crude oil and natural gas revenues were 8.1% for the nine months ended September 30, 2014 compared to 8.3% for the nine months ended September 30, 2013. The decrease was due to significant growth over the past year in our SCOOP operations and resulting increase in revenues from Oklahoma, which has lower production tax rates compared to our other key operating areas.

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

	Nine months ended September 30,	
In thousands	2014	2013
Geological and geophysical costs	$20,390	$19,958
Exploratory dry hole costs	9,142	9,180
Exploration expenses	$29,532	$29,138

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $268.2 million, or 39%, to $963.4 million for the nine months ended September 30, 2014 compared to $695.2 million for the same period in 2013 primarily due to a 25% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Nine months ended September 30,	
$/Boe	2014	2013
Crude oil and natural gas	$20.80	$18.84
Other equipment	0.31	0.23
Asset retirement obligation accretion	0.06	0.06
Depreciation, depletion, amortization and accretion	$21.17	$19.13

The increase in DD&A per Boe for the nine months ended September 30, 2014 resulted from an increased use of enhanced completion methods that increased completed well costs. Additionally, certain exploratory wells, primarily in non-core areas, resulted in more expensive reserve additions. These factors contributed to an increase in DD&A on a per-Boe basis over the prior period.

Property Impairments. Property impairments increased in the nine months ended September 30, 2014 by $61.1 million to $223.1 million compared to $162.0 million for the nine months ended September 30, 2013.

Impairments of non-producing properties increased $31.4 million during the nine months ended September 30, 2014 to $153.7 million compared to $122.3 million for the nine months ended September 30, 2013. The increase resulted from a larger base of amortizable costs in the current period coupled with higher rates of amortization in certain areas resulting from changes in management's estimates of undeveloped properties not expected to be developed before lease expiration.

Impairment provisions for proved properties were $69.3 million for the nine months ended September 30, 2014, primarily reflecting fair value adjustments made for certain properties in non-core areas of our South region. Impairment provisions for proved properties were $39.6 million for the nine months ended September 30, 2013, primarily reflecting uneconomic results for certain wells drilled in the Niobrara play in Colorado and Wyoming.

General and Administrative Expenses. G&A expenses increased $30.6 million, or 30%, to $134.4 million for the nine months ended September 30, 2014 from $103.8 million for the comparable period in 2013. G&A expenses include non-cash charges for equity compensation of $39.4 million and $29.5 million for the nine months ended September

30, 2014 and 2013 respectively. The increase in equity compensation expense in 2014 resulted from a higher value of restricted stock grants being made in 2013 and 2014 due to employee growth, which resulted in increased expense recognition in the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013.

G&A expenses other than equity compensation increased $20.7 million, or 28%, for the nine months ended September 30, 2014 compared to the same period in 2013. The increase was primarily due to an increase in personnel costs and office-related expenses associated with our growth.

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

	Nine months ended September 30,	
$/Boe	2014	2013
General and administrative expenses	$2.08	$2.00
Non-cash equity compensation	0.87	0.81
Corporate relocation expenses	—	0.04
Total general and administrative expenses	$2.95	$2.85

Interest Expense. Interest expense increased $38.1 million, or 22%, to $209.7 million for the nine months ended September 30, 2014 compared to $171.6 million for the nine months ended September 30, 2013 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the nine months ended September 30, 2014 was approximately $5.5 billion with a weighted average interest rate of 4.9% compared to a weighted average outstanding long-term debt balance of $4.2 billion and a weighted average interest rate of 5.2% for the comparable period in 2013. The increase in outstanding debt resulted from higher borrowings being incurred to fund our increased capital budget.

Income Taxes. We recorded income tax expense for the nine months ended September 30, 2014 of $507.0 million compared to $370.8 million for the nine months ended September 30, 2013. We provided for income taxes at a combined federal and state tax rate of approximately 37% for both the nine months ended September 30, 2014 and 2013 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 credit facility and the issuance of debt and equity securities. As of September 30, 2014, we had $152.3 million of cash and cash equivalents and approximately $1.75 billion of borrowing availability on our credit facility. We had no outstanding borrowings on our credit facility at September 30, 2014. As of October 31, 2014, we continued to have approximately $1.75 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 $2.28 billion and $1.98 billion for the nine months ended September 30, 2014 and 2013, respectively. The increase in operating cash flows was primarily due to higher crude oil and natural gas revenues driven by higher sales volumes, which were partially offset by an increase in cash losses on matured derivatives and increases in production expenses, production taxes, general and administrative expenses, interest expense and other expenses associated with the growth of our operations over the past year.

Cash flows used in investing activities

During the nine months ended September 30, 2014 and 2013, we had cash flows used in investing activities (excluding proceeds from asset sales) of $3.36 billion and $2.82 billion, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Cash acquisition capital expenditures totaled $179.8 million and $196.9 million for the nine months ended September 30, 2014 and 2013, respectively. Cash capital expenditures excluding acquisitions totaled $3.18 billion and $2.62 billion for the nine months ended September 30, 2014 and 2013, respectively, the increase of which was driven by an increase in drilling activity in 2014.

The use of cash for capital expenditures during the nine months ended September 30, 2014 was partially offset by proceeds received from asset dispositions. Proceeds from the sale of assets amounted to $129.3 million during the nine months ended September 30, 2014, primarily related to dispositions of properties in the Niobrara play in Colorado and Wyoming in March 2014 for proceeds totaling $30.3 million and $85.8 million of proceeds received in conjunction with the disposition of a portion of our Northwest Cana properties in Oklahoma in September 2014.

Cash flows from financing activities

Net cash provided by financing activities for the nine months ended September 30, 2014 was $1.07 billion primarily resulting from the receipt of $1.68 billion of net proceeds from the issuances of $1.0 billion of 3.8% Senior Notes due 2024 and $700 million of 4.9% Senior Notes due 2044 in May 2014, partially offset by net repayments of $275 million on our credit facility and the July 2014 redemption of our 2019 Notes at a make-whole amount of $317.5 million.

Net cash provided by financing activities for the nine months ended September 30, 2013 was $876.7 million primarily resulting from the receipt of $1.48 billion of net proceeds from the issuance of $1.5 billion of 4.5% Senior Notes due 2023 in April 2013, partially offset by net repayments of $595 million on our credit facility.

Future Sources of Financing

Although we cannot provide any assurance, we believe funds from operating cash flows, our remaining cash balance, proceeds of approximately $433 million received upon early liquidation of crude oil derivative positions in October 2014 as discussed below, 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. If operating cash flows are materially impacted by an extended decline in commodity prices, we have the ability to reduce our capital expenditures to be in line with operating cash flows and can utilize the availability on our credit facility if needed to fund any deficit and satisfy our obligations. 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, 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.

Credit facility

We have an unsecured credit facility, maturing on May 16, 2019, with aggregate lender commitments totaling $1.75 billion, which may be increased up to $4.0 billion upon agreement between the Company and participating lenders. We had no outstanding borrowings and approximately $1.75 billion of availability on our credit facility at September 30, 2014. As of October 31, 2014, we continued to have approximately $1.75 billion of borrowing availability on our credit facility with no borrowings outstanding.

Our credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, incur liens, engage in sale and leaseback transactions, and merge, consolidate or sell all or substantially all of our assets. Our credit facility also contains a requirement that we maintain a net debt to capitalization ratio of no greater than 0.65 to 1.00. This ratio represents the ratio of net debt (total debt less cash and cash equivalents) divided by the sum of net debt plus total shareholders' equity. We were in compliance with the credit facility covenants at September 30, 2014. 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.

Derivative liquidations

In October 2014, following a decrease in crude oil commodity prices and related increase in the fair value of our derivative assets, substantially all of our crude oil derivative contracts outstanding as of September 30, 2014 were settled prior to the expiration of their contractual maturities, resulting in the receipt of cash proceeds totaling approximately $433 million. Proceeds from the settlements are expected to be used to fund a portion of our 2014 and 2015 capital programs and for general corporate purposes. See Note 4. Derivative Instruments in Notes to Unaudited Condensed Consolidated Financial Statements for further discussion including a summary of remaining derivative contracts in place as of October 31, 2014.

Future Capital Requirements

Senior notes

Our long-term debt includes outstanding senior note obligations totaling $5.8 billion at September 30, 2014. Scheduled maturities of our senior notes begin in October 2020. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. For further information on the maturity dates, semi-annual interest payment dates, optional redemption periods and covenant restrictions related to our senior notes, refer to Note 6. Long-Term Debt in Notes to Unaudited Condensed Consolidated Financial Statements. We were in compliance with our senior note covenants at September 30, 2014 and expect to maintain compliance for at least the next 12 months. We do not believe the restrictive covenants under the senior note indentures 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 no material assets or operations, fully and unconditionally guarantee the senior notes. Our other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

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 September 2014 our Board of Directors approved an increase to our 2014 capital expenditures budget to $4.55 billion, excluding property acquisitions. Our previous 2014 capital expenditures budget was $4.05 billion. The revised budget primarily reflects an increased use of enhanced completion techniques and the acceleration of our drilling and completion activities in the second half of 2014 resulting from the success of our enhanced completion testing program in the Bakken field and favorable returns being achieved in the SCOOP play. Our revised 2014 budget is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$4,085
Land costs	300
Capital facilities, workovers and other corporate assets	145
Seismic	20
Total 2014 capital budget, excluding acquisitions	$4,550

During the nine months ended September 30, 2014, we participated in the completion of 816 gross (295.5 net) wells and invested approximately $3,418.0 million in our capital program, excluding $179.8 million of unbudgeted acquisitions and including $10.3 million of seismic costs and $235.4 million of capital costs associated with increased accruals for capital expenditures. Our 2014 year-to-date capital expenditures were allocated as follows:

In millions	Amount
Exploration and development drilling	$3,051.5
Land costs	208.7
Capital facilities, workovers and other corporate assets	147.5
Seismic	10.3
Capital expenditures, excluding acquisitions	3,418.0
Acquisitions of producing properties	48.3
Acquisitions of non-producing properties	131.5
Total acquisitions	179.8
Total capital expenditures	$3,597.8

In September 2014, our Board of Directors approved a 2015 capital expenditures budget of $5.20 billion excluding acquisitions. Due to recently lower commodity prices, we have adjusted our 2015 capital expenditures budget to $4.60 billion, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$4,030
Land costs	300
Capital facilities, workovers and other corporate assets	245
Seismic	25
Total 2015 capital budget, excluding acquisitions	$4,600

Our 2015 capital program is expected to continue focusing on exploratory and development drilling in the Bakken field and SCOOP play.

Our 2015 capital expenditures budget has been established based on an expectation of available cash flows from operations and availability under our credit facility. Should expected available cash flows from operations materially differ from expectations due to a decline in commodity prices, we believe our credit facility has sufficient availability to fund any deficit or that we can reduce our capital expenditures to be in line with cash flows from operations.

The actual amount and timing of our capital expenditures may differ materially from our budget as a result of, among other things, access to capital, available cash flows, unbudgeted acquisitions, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of transportation capacity, changes in commodity prices, and regulatory, technological and competitive developments. A decline in commodity prices could cause us to curtail our actual capital expenditures. Conversely, an increase in commodity prices could result in increased capital expenditures. 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 competitive terms.

Commitments

Following is a discussion of various future commitments of the Company as of September 30, 2014. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of September 30, 2014, we had drilling rig contracts with various terms extending through July 2018. 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. Future commitments as of September 30, 2014 total approximately $675 million, of which $66 million is expected to be incurred in the remainder of 2014, $246 million in 2015, $213 million in 2016, $122 million in 2017 and $28 million in 2018. 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.

Pipeline transportation commitments – We have entered into firm transportation commitments to guarantee pipeline access capacity on operational crude oil and natural gas pipelines in order to reduce the impact of possible production curtailments that may arise due to limited transportation capacity. The commitments, which have varying terms extending as far as 2025, require the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of September 30, 2014 under the operational pipeline transportation arrangements amount to approximately $1.0 billion, of which $40 million is expected to be incurred in the remainder of 2014, $181 million in 2015, $186 million in 2016, $180 million in 2017, $175 million in 2018, and $241 million thereafter.

Further, we are a party to an additional firm transportation commitment for a future crude oil pipeline project being considered for development that is not yet operational. The project requires the granting of regulatory approvals and requires additional construction efforts by the counterparty before being completed. Future commitments under the non-operational arrangement total approximately $260 million at September 30, 2014, representing aggregate transportation charges expected to be incurred over the five year term beginning when the proposed pipeline project is completed and becomes operational. The exact 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 this non-operational arrangement 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.

Our pipeline commitments are for production primarily 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.

Cost sharing commitment – We have entered into an arrangement to share certain costs associated with a local utility company's construction and installation of electrical infrastructure that will provide service to parts of North Dakota where the Company operates. This arrangement extends through January 2016 and requires the Company to make scheduled periodic payments based on the projected total cost of the project and the progress of construction. Future commitments under the arrangement as of September 30, 2014 total approximately $13 million, of which $3 million is expected to be incurred in the remainder of 2014, $8 million in 2015, and $2 million in 2016.

We believe our cash flows from operations, our remaining cash balance, proceeds received upon early liquidation of crude oil derivative positions in October 2014, 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, 2013.

Recent Accounting Pronouncements Not Yet Adopted

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers (Topic 606). The standard's core principle is that an entity shall recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard generally requires an entity to identify performance obligations in its contracts, estimate the amount of variable consideration to be received in the transaction price, allocate the transaction price to each separate performance obligation, and recognize revenue as obligations are satisfied. The standard will be effective for annual and interim periods beginning after December 15, 2016. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. We are evaluating the impact of the provisions of ASU 2014-09; however, the standard is not expected to have a material effect on our financial position, results of operations or cash flows.

We are monitoring the joint standard-setting efforts of the Financial Accounting Standards Board and International Accounting Standards Board. There are a number of pending accounting standards being targeted for completion in 2014 and beyond, including, but not limited to, standards relating to 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.

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, non-cash equity compensation expense, and losses on extinguishment of debt. 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. Further, 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. 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.

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

In thousands	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Net income	$533,521	$167,498	$863,293	$631,395
Interest expense	73,912	62,756	209,728	171,609
Provision for income taxes	313,340	98,373	507,015	370,822
Depreciation, depletion, amortization and accretion	363,677	244,721	963,409	695,189
Property impairments	85,561	42,167	223,085	161,960
Exploration expenses	13,514	8,173	29,532	29,138
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	(473,999)	203,774	(171,801)	89,548
Total cash paid on derivatives, net	190	(40,349)	(97,217)	(51,910)
Non-cash (gain) loss on derivatives, net	(473,809)	163,425	(269,018)	37,638
Non-cash equity compensation	13,402	10,462	39,419	29,460
Loss on extinguishment of debt	24,517	—	24,517	—
EBITDAX	$947,635	$797,575	$2,590,980	$2,127,211

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

In thousands	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Net cash provided by operating activities	$2,277,851	$1,978,453
Current income tax provision	2,278	10,223
Interest expense	209,728	171,609
Exploration expenses, excluding dry hole costs	20,390	19,958
Gain (loss) on sale of assets, net	(952)	112
Other, net	(12,850)	(3,848)
Changes in assets and liabilities	94,535	(49,296)
EBITDAX	$2,590,980	$2,127,211

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 nine months ended September 30, 2014, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $427 million for each $10.00 per barrel change in crude oil prices and $111 million for each $1.00 per Mcf change in natural gas prices.
To reduce price risk caused by these market fluctuations, we may economically 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. We may choose not to hedge future production if the pricing environment for certain time periods is not deemed to be favorable. While hedging, if utilized, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements.
Changes in commodity prices during the nine months ended September 30, 2014 had an overall positive impact on the fair value of our derivative instruments. For the nine months ended September 30, 2014, we recognized cash losses on derivatives of $97.2 million and reported a non-cash mark-to-market gain on derivatives of $269.0 million.
The fair value of our crude oil derivative instruments at September 30, 2014 was a net asset of $162.5 million. In October 2014, following a decrease in crude oil commodity prices and related increase in the fair value of our derivative assets, substantially all of our crude oil derivative contracts outstanding as of September 30, 2014 were settled prior to the expiration of their contractual maturities, resulting in the receipt of cash proceeds totaling approximately $433 million. See Note 4. Derivative Instruments in Notes to Unaudited Condensed Consolidated Financial Statements for further discussion including a summary of remaining derivative contracts in place as of October 31, 2014. As of October 31, 2014, the fair value of our remaining crude oil derivative instruments was a net liability of approximately $7 million.
The fair value of our natural gas derivative instruments at September 30, 2014 was a net asset of $11.8 million. An assumed increase in the forward prices used in the September 30, 2014 valuation of our natural gas derivatives of $1.00 per MMBtu would change our natural gas derivative asset valuation to a net liability of approximately $53 million at September 30, 2014. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative valuation to a net asset of approximately $80 million at September 30, 2014.
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 ($687 million in receivables at September 30, 2014), our joint interest receivables ($507 million at September 30, 2014), and counterparty credit risk associated with our derivative instrument receivables ($174 million at September 30, 2014, which subsequently decreased to approximately $20 million at October 31, 2014 after liquidation of substantially all of our crude oil derivative instruments).
We monitor our exposure to counterparties on crude oil and natural gas sales primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's credit worthiness. We have not generally required our counterparties to provide collateral to support crude oil and natural gas sales receivables owed to us. Historically, our credit losses on crude oil and natural gas sales receivables have been immaterial.
Joint interest receivables arise from billing entities 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 $43.0 million at September 30, 2014, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We also have the right to place a lien on our co-owners interest in the well to redirect production proceeds in order to secure payment or, if necessary, foreclose on the interest. Historically, our credit losses on joint interest receivables have been immaterial.

Our use of derivative instruments involves the risk that our counterparties will be unable to meet their commitments under the arrangements. We manage this risk by using multiple counterparties who we consider to be financially strong in order to minimize our exposure to credit risk with any individual counterparty. 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 and we had no outstanding borrowings on our credit facility at October 31, 2014.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) was performed under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of September 30, 2014 to ensure that information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and that information required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the three months ended September 30, 2014, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Controls and Procedures

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

PART II. Other Information

ITEM 1. Legal Proceedings

During the nine months ended September 30, 2014 there have been no material changes with respect to the legal proceedings previously disclosed in our 2013 Form 10-K that was filed with the SEC on February 27, 2014. 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 2013 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 2013 Form 10-K, which could materially affect our business, financial condition or future results. The risks described in this Form 10-Q, if any, and in our 2013 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 three months ended September 30, 2014. The share and related price amounts presented below have been retroactively adjusted, where applicable, to reflect the Company's 2-for-1 stock split occurring in September 2014.

Period	Total number of shares purchased		Average price paid per share		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 programs (3)
July 1, 2014 to July 31, 2014	846	(1)	$75.77	(1)	—	—
August 1, 2014 to August 31, 2014	16,536	(1)	72.25	(1)	—	—
September 1, 2014 to September 30, 2014	95,499	(2)	68.79	(2)	—	—
Total	112,881		$69.35		—	—

(1) In connection with restricted stock grants under the Company's 2005 Long-Term Incentive Plan ("2005 Plan") and 2013 Long-Term Incentive Plan ("2013 Plan"), we adopted a policy that enables employees to surrender shares to cover their tax liability. In May 2013, the 2013 Plan was adopted and replaced the Company's 2005 Plan. Restricted stock awards granted under the 2005 Plan prior to the adoption of the 2013 Plan will remain outstanding in accordance with their terms. These shares purchased above represent shares surrendered by employees to cover tax liabilities. The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares. We paid the associated taxes to the Internal Revenue Service.

(2) Of this amount, 23,500 shares represent shares surrendered by employees to cover tax liabilities at an average price per share of $72.88. Additionally, the amount includes 71,999 shares of our common stock purchased by Harold G. Hamm, our Chairman, Chief Executive Officer, and controlling shareholder in open-market transactions at an average price per share of $67.45.

(3) We are unable to determine at this time the total amount of securities or approximate dollar value of 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.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

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.

SIGNATURE

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

		CONTINENTAL RESOURCES, INC.	
Date:	November 5, 2014	By:	/s/ John D. Hart
			John D. Hart
			Sr. Vice President, Chief Financial Officer and Treasurer
			(Duly Authorized Officer and Principal Financial Officer)

Index to Exhibits

3.1	Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. filed 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.
10.1*†	General Release and Waiver Agreement between Winston F. "Rick" Bott and Continental Resources, Inc. dated September 11, 2014.
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.