CONTINENTAL RESOURCES, INC
Form 10-Q
August 06, 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 June 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	73-0767549
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
20 N. Broadway, Oklahoma City, Oklahoma	73102
(Address of principal executive offices)	(Zip Code)

(405) 234-9000
(Registrant's telephone number, including area code)
Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

186,109,846 shares of our $0.01 par value common stock were outstanding on August 1, 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.
"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.
“hydraulic fracturing” A process involving the high pressure injection of water, sand and additives into rock formations to stimulate crude oil and natural gas production.
“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 multi-stage fracturing technologies.
"royalty interest" Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.
"SCOOP" Refers to the South Central Oklahoma Oil Province, a term we use to describe an emerging area of crude oil and liquids-rich natural gas properties located in the Anadarko basin of south central Oklahoma.
"unconventional play" An area believed to be capable of producing crude oil and natural gas occurring in accumulations that are regionally extensive, but 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

	June 30, 2014	December 31, 2013
In thousands, except par values and share data	(Unaudited)	
Assets		
Current assets:		
Cash and cash equivalents	$776,963	$28,482
Receivables:		
Crude oil and natural gas sales	746,569	643,498
Affiliated parties	15,014	13,107
Joint interest and other, net	386,586	349,579
Derivative assets	—	3,616
Inventories	77,959	54,440
Deferred and prepaid taxes	100,664	44,337
Prepaid expenses and other	19,281	10,207
Total current assets	2,123,036	1,147,266
Net property and equipment, based on successful efforts method of accounting	12,166,106	10,721,272
Net debt issuance costs and other	87,815	72,644
Noncurrent derivative assets	549	—
Total assets	$14,377,506	$11,941,182
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable trade	$1,044,099	$885,289
Revenues and royalties payable	332,914	291,772
Payables to affiliated parties	7,336	5,436
Accrued liabilities and other	207,632	198,113
Derivative liabilities	236,694	90,535
Current portion of long-term debt	300,467	2,011
Total current liabilities	2,129,142	1,473,156
Long-term debt, net of current portion	5,832,872	4,713,821
Other noncurrent liabilities:		
Deferred income tax liabilities	1,984,802	1,736,812
Asset retirement obligations, net of current portion	59,367	54,353
Noncurrent derivative liabilities	63,394	7,829
Other noncurrent liabilities	3,668	2,093
Total other noncurrent liabilities	2,111,231	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; 186,105,662 shares issued and outstanding at June 30, 2014; 185,658,659 shares issued and outstanding at December 31, 2013	1,861	1,857
Additional paid-in capital	1,273,401	1,252,034
Retained earnings	3,028,999	2,699,227

Total shareholders’ equity	4,304,261	3,953,118
Total liabilities and shareholders’ equity	$14,377,506	$11,941,182

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

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

	Three months ended June 30,		Six months ended June 30,	
In thousands, except per share data	2014	2013	2014	2013
Revenues				
Crude oil and natural gas sales	$1,112,998	$858,029	$2,085,145	$1,614,246
Crude oil and natural gas sales to affiliates	25,087	26,463	55,273	46,177
Gain (loss) on derivative instruments, net	(262,524)	199,056	(302,198)	114,225
Crude oil and natural gas service operations	10,534	9,509	20,370	21,052
Total revenues	886,095	1,093,057	1,858,590	1,795,700
Operating costs and expenses				
Production expenses	84,236	73,143	160,211	134,460
Production and other expenses to affiliates	285	309	1,196	795
Production taxes and other expenses	97,025	74,541	175,327	139,384
Exploration expenses	11,205	11,151	16,018	20,965
Crude oil and natural gas service operations	5,979	7,317	14,053	15,914
Depreciation, depletion, amortization and accretion	326,871	236,790	599,732	450,468
Property impairments	79,316	79,712	137,524	119,793
General and administrative expenses	46,919	35,873	90,455	69,690
(Gain) loss on sale of assets, net	(2,135)	349	6,363	213
Total operating costs and expenses	649,701	519,185	1,200,879	951,682
Income from operations	236,394	573,872	657,711	844,018
Other income (expense):				
Interest expense	(72,841)	(61,378)	(135,816)	(108,853)
Other	793	634	1,552	1,180
	(72,048)	(60,744)	(134,264)	(107,673)
Income before income taxes	164,346	513,128	523,447	736,345
Provision for income taxes	60,808	189,858	193,675	272,448
Net income	$103,538	$323,270	$329,772	$463,897
Basic net income per share	$0.56	$1.76	$1.79	$2.52
Diluted net income per share	$0.56	$1.75	$1.78	$2.51

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	185,658,659	$1,857	$1,252,034	$2,699,227	$3,953,118
Net income (unaudited)	—	—	—	329,772	329,772
Stock-based compensation (unaudited)	—	—	26,012	—	26,012
Restricted stock:					
Granted (unaudited)	602,217	6	—	—	6
Repurchased and canceled (unaudited)	(38,216)	(1)	(4,645)	—	(4,646)
Forfeited (unaudited)	(116,998)	(1)	—	—	(1)
Balance at June 30, 2014 (unaudited)	186,105,662	$1,861	$1,273,401	$3,028,999	$4,304,261

The accompanying notes are an integral part of these condensed consolidated financial statements.
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Continental Resources, Inc. and Subsidiaries
Unaudited Condensed Consolidated Statements of Cash Flows

	Six months ended June 30,	
In thousands	2014	2013
Cash flows from operating activities		
Net income	$329,772	$463,897
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	606,638	448,639
Property impairments	137,524	119,793
Non-cash (gain) loss on derivatives, net	204,791	(125,787)
Stock-based compensation	26,017	18,998
Provision for deferred income taxes	190,571	266,618
Dry hole costs	4,383	8,063
Loss on sale of assets, net	6,363	213
Other, net	4,411	2,466
Changes in assets and liabilities:		
Accounts receivable	(144,821)	(100,542)
Inventories	(23,519)	4,658
Prepaid expenses and other	(7,938)	(6,526)
Accounts payable trade	44,505	21,678
Revenues and royalties payable	42,051	12,920
Accrued liabilities and other	9,186	16,018
Other noncurrent assets and liabilities	2,519	5,839
Net cash provided by operating activities	1,432,453	1,156,945
Cash flows from investing activities		
Exploration and development	(2,052,870)	(1,823,215)
Purchase of producing crude oil and natural gas properties	(33,606)	(9,311)
Purchase of other property and equipment	(29,829)	(18,545)
Proceeds from sale of assets	39,018	894
Net cash used in investing activities	(2,077,287)	(1,850,177)
Cash flows from financing activities		
Credit facility borrowings	1,105,000	440,000
Repayment of credit facility	(1,380,000)	(1,035,000)
Proceeds from issuance of Senior Notes	1,681,834	1,479,375
Repayment of other debt	(999)	(969)
Debt issuance costs	(7,874)	(2,231)
Repurchase of equity grants	(4,646)	(3,259)
Net cash provided by financing activities	1,393,315	877,916
Net change in cash and cash equivalents	748,481	184,684
Cash and cash equivalents at beginning of period	28,482	35,729
Cash and cash equivalents at end of period	$776,963	$220,413

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 six months ended June 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 emerging 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 six months ended June 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.
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 June 30, 2014 and for the three and six month periods ended June 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.
Inventories
Inventories are stated at the lower of cost or market and consist of the following:

In thousands	June 30, 2014	December 31, 2013

Tubular goods and equipment	$17,892	$11,139
Crude oil	60,067	43,301
Total	$77,959	$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	June 30, 2014	December 31, 2013
Crude oil line fill and tank requirements	422	370
Temporarily stored crude oil	624	344
Total	1,046	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 six months ended June 30, 2014 and 2013.

	Three months ended June 30,		Six months ended June 30,	
In thousands, except per share data	2014	2013	2014	2013
Income (numerator):				
Net income - basic and diluted	$103,538	$323,270	$329,772	$463,897
Weighted average shares (denominator):				
Weighted average shares - basic	184,373	184,039	184,351	184,019
Non-vested restricted stock	794	700	843	685
Weighted average shares - diluted	185,167	184,739	185,194	184,704
Net income per share:				
Basic	$0.56	$1.76	$1.79	$2.52
Diluted	$0.56	$1.75	$1.78	$2.51

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 currently 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 $7.7 million for the three months ended June 30, 2013, including transactions with an affiliate totaling $1.2 million, and $15.3 million for the six months ended June 30, 2013, including transactions with an affiliate totaling $2.4 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.

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

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.

	Six months ended June 30,	
In thousands	2014	2013
Supplemental cash flow information:		
Cash paid for interest	$122,879	$88,856
Cash paid for income taxes	2,012	16,883
Cash received for income tax refunds	(5)	(173)
Non-cash investing activities:		
Increase in accrued capital expenditures	115,956	59,414
Asset retirement obligation additions and revisions, net	3,710	3,403

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 has utilized 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.

At June 30, 2014, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below.

Crude Oil - NYMEX WTI

Period and Type of Contract	Bbls	Swaps Weighted Average Price
July 2014 - December 2014		
Swaps - WTI	6,670,000	$96.22

Continental Resources, Inc. and Subsidiaries
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Crude Oil - ICE Brent		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	Bbls	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
July 2014 - December 2014						
Swaps - ICE Brent	9,016,000	$103.29				
Collars - ICE Brent	1,104,000		$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

Natural Gas - NYMEX Henry Hub		Swaps	Collars Floors		Ceilings	
Period and Type of Contract	MMBtus	Weighted Average Price	Range	Weighted Average Price	Range	Weighted Average Price
July 2014 - December 2014						
Swaps - Henry Hub	61,640,000	$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 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 June 30,		Six months ended June 30,	
In thousands	2014	2013	2014	2013
Cash received (paid) on derivatives:				
Crude oil fixed price swaps	$(50,499)	$2,081	$(73,022)	$(7,512)
Crude oil collars	(1,453)	254	(2,037)	379
Natural gas fixed price swaps	(12,191)	(7,087)	(22,348)	(4,429)
Cash paid on derivatives, net	(64,143)	(4,752)	(97,407)	(11,562)
Non-cash gain (loss) on derivatives:				
Crude oil fixed price swaps	(201,482)	141,912	(187,792)	108,548
Crude oil collars	(4,369)	15,968	914	2,206
Natural gas fixed price swaps	7,494	45,928	(17,907)	15,033
Natural gas collars	(24)	—	(6)	—
Non-cash gain (loss) on derivatives, net	(198,381)	203,808	(204,791)	125,787
Gain (loss) on derivative instruments, net	$(262,524)	$199,056	$(302,198)	$114,225

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.
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	June 30, 2014	December 31, 2013
Commodity derivative assets:		
Gross amounts of recognized assets	$549	$4,213
Gross amounts offset on balance sheet	—	(597)
Net amounts of assets on balance sheet	549	3,616
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(300,418)	(125,709)
Gross amounts offset on balance sheet	330	27,345
Net amounts of liabilities on balance sheet	$(300,088)	$(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	June 30, 2014	December 31, 2013
Derivative assets	$—	$3,616
Noncurrent derivative assets	549	—
Net amounts of assets on balance sheet	549	3,616
Derivative liabilities	(236,694)	(90,535)
Noncurrent derivative liabilities	(63,394)	(7,829)
Net amounts of liabilities on balance sheet	(300,088)	(98,364)
Total derivative liabilities, net	$(299,539)	$(94,748)

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 June 30, 2014 and December 31, 2013.

	Fair value measurements at June 30, 2014 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$(290,591)	$—	$(290,591)
Collars	—	(8,948)	—	(8,948)
Total	$—	$(299,539)	$—	$(299,539)

	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 June 30, 2014 and June 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 $27.5 million and $31.3 million for the three and six months ended June 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 $10.2 million. Impairment provisions for proved properties totaled $39.6 million for the three and six months ended June 30, 2013, primarily reflecting 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 June 30, 2013.

Certain unproved crude oil and natural gas properties were impaired during the three and six months ended June 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 June 30,		Six months ended June 30,	
In thousands	2014	2013	2014	2013
Proved property impairments	$27,529	$39,635	$31,291	$39,635
Unproved property impairments	51,787	40,077	106,233	80,158
Total	$79,316	$79,712	$137,524	$119,793

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.

	June 30, 2014		December 31, 2013	
In thousands	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Credit facility	$—	$—	$275,000	$275,000
Note payable	17,471	15,764	18,470	16,500
8.25% Senior Notes due 2019	298,422	316,950	298,305	327,800
7.375% Senior Notes due 2020	198,770	223,100	198,695	223,700
7.125% Senior Notes due 2021	400,000	453,600	400,000	450,300
5% Senior Notes due 2022	2,024,180	2,172,600	2,025,362	2,063,300
4.5% Senior Notes due 2023	1,500,000	1,595,250	1,500,000	1,519,400
3.8% Senior Notes due 2024	996,474	1,009,000	—	—
4.9% Senior Notes due 2044	698,022	720,930	—	—
Total debt	$6,133,339	$6,507,194	$4,715,832	$4,876,000

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.

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

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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 June 30, 2014 and December 31, 2013:

In thousands	June 30, 2014	December 31, 2013
Credit facility	$—	$275,000
Note payable	17,471	18,470
8.25% Senior Notes due 2019 (1)	298,422	298,305
7.375% Senior Notes due 2020 (2)	198,770	198,695
7.125% Senior Notes due 2021 (3)	400,000	400,000
5% Senior Notes due 2022 (4)	2,024,180	2,025,362
4.5% Senior Notes due 2023 (3)	1,500,000	1,500,000
3.8% Senior Notes due 2024 (5)	996,474	—
4.9% Senior Notes due 2044 (6)	698,022	—
Total debt	6,133,339	4,715,832
Less: Current portion of long-term debt (7)	(300,467)	(2,011)
Long-term debt, net of current portion	$5,832,872	$4,713,821

(1) The carrying amount is net of unamortized discounts of $1.6 million and $1.7 million at June 30, 2014 and December 31, 2013, respectively. The 2019 Notes were redeemed on July 11, 2014. See Note 10. Subsequent Event.

(2) The carrying amount is net of unamortized discounts of $1.2 million and $1.3 million at June 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 $24.2 million and $25.4 million at June 30, 2014 and December 31, 2013, respectively.

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

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

(7) Balance at June 30, 2014 is mainly comprised of the $298.4 million carrying amount of the Company's 2019 Notes that were redeemed on July 11, 2014 as disclosed in Note 10. Subsequent Event.

Credit Facility

On May 16, 2014, the Company entered into a new unsecured credit facility (the “New Credit Facility”) that provides for increased aggregate commitments and an extended maturity beyond the term of its previous credit facility. The New Credit Facility matures on May 16, 2019 and has aggregate commitments totaling $1.75 billion, which may be increased up to $4.0 billion in the future upon agreement between the Company and participating lenders. The New Credit Facility replaced the Company’s previous $1.5 billion unsecured credit facility that was due to mature on July 1, 2015.

The Company had no outstanding borrowings and approximately $1.75 billion of unused commitments on its New Credit Facility at June 30, 2014. Borrowings under the New 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 New 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 June 30, 2014.

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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. The remaining net proceeds will be used to fund a portion of the Company's 2014 capital program, to finance the redemption of its 8.25% Senior Notes due 2019 (see Note 10) and for general corporate purposes.

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 June 30, 2014, excluding the 2019 Notes that were redeemed in July 2014 as disclosed in Note 10. Subsequent Event.

	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 June 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.

Note 7. Commitments and Contingencies

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

Drilling commitments – As of June 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 June 30, 2014 total approximately $335 million, of which $64 million is expected to be incurred in the remainder of 2014, $92 million in 2015, $86 million in 2016, $65 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 2024, require the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of June 30, 2014 under the operational pipeline transportation arrangements amount to approximately $91 million, of which $10 million is expected to be incurred in the remainder of 2014, $20 million in 2015, $16 million in 2016, $11 million in 2017, $6 million in 2018, and $28 million thereafter.

Further, the Company is a party to additional firm transportation commitments for future crude oil and natural gas pipeline projects being constructed or considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require additional construction efforts by counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.2 billion at June 30, 2014, which includes approximately $96 million subject to a joint tariff arrangement between an unaffiliated party and an affiliate controlled by the Company's principal shareholder. These commitments represent aggregate transportation charges expected to be incurred over the terms of the arrangements assuming the proposed pipeline projects are completed and become 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 these non-operational arrangements cannot be predicted with certainty and may not be incurred on a ratable basis over a calendar year or may not be incurred at all. Although timing is uncertain, operators have indicated that certain pipeline projects may become operational in the fourth quarter of 2014 and first half of 2015, which, if accurate, would obligate the Company for transportation charges totaling $36 million in 2014, $160 million in 2015, $168 million annually in years 2016 through 2018, and $206 million thereafter.

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 June 30, 2014 total approximately $16 million, of which $6 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 June 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.

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

Note 8. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2005 Long-Term Incentive Plan (“2005 Plan”) 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 June 30,		Six months ended June 30,	
In thousands	2014	2013	2014	2013
Non-cash equity compensation	$14,978	$9,756	$26,017	$18,998

In May 2013, the Company adopted the 2013 Plan and reserved a maximum of 9,840,036 shares of common stock 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 June 30, 2014, the Company had a maximum of 9,091,028 shares of restricted stock 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 six months ended June 30, 2014 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2013	1,357,156	$74.99
Granted	602,217	122.41
Vested	(131,556)	73.29
Forfeited	(116,998)	85.06
Non-vested restricted shares outstanding at June 30, 2014	1,710,819	$91.12

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 six months ended June 30, 2014 at the vesting date was approximately $16.1 million. As of June 30, 2014, there was approximately $96 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 1.5 years.

Note 9. Property Dispositions

During the six months ended June 30, 2014, the Company sold certain non-strategic properties in various areas to third parties for proceeds totaling $39.0 million. In connection with the transactions, the Company recognized pre-tax losses totaling $6.4 million. The disposed properties represented an immaterial portion of the Company’s total proved reserves, production, and revenues.

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Note 10. Subsequent Event

On July 11, 2014, the Company fully redeemed its $300 million of 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 $324.4 million, or 108.12% of par, representing a make-whole amount calculated in accordance with the terms of the 2019 Notes and related indenture plus accrued and unpaid interest through the redemption date. The Company will record a pre-tax loss on extinguishment of debt related to the redemption of approximately $24 million, which will be reflected in third quarter 2014 results. The carrying amount of the 2019 Notes has been reflected as a current liability in the caption "Current portion of long-term debt" in the condensed consolidated balance sheet at June 30, 2014.

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 six months ended June 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 emerging 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 second quarter of 2014, our crude oil and natural gas production averaged 167,953 Boe per day, representing a 10% increase over average daily production of 152,471 Boe per day for the first quarter of 2014 and a 24% increase over average daily production of 135,700 Boe per day for the second quarter of 2013. Crude oil and natural gas production averaged 160,255 Boe per day for the six months ended June 30, 2014, a 25% increase over average daily production of 128,655 Boe per day for the comparable 2013 period. Crude oil represented 69% and 70% of our total production for the three and six months ended June 30, 2014, respectively, compared to 71% for both the three and six months ended June 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 108,573 Boe per day for the second quarter of 2014, an 11% increase over the first quarter of 2014 and 23% higher than the second quarter of 2013. Total Bakken production averaged 103,046 Boe per day for the six months ended June 30, 2014, a 25% increase over the first half of 2013.

Production in the emerging SCOOP play averaged 34,265 Boe per day for the second quarter of 2014, a 17% increase over the first quarter of 2014 and 95% higher than the second quarter of 2013. SCOOP production averaged 31,827 Boe per day for the six months ended June 30, 2014, an increase of 100% over the first half of 2013.

Crude oil and natural gas revenues for the second quarter of 2014 increased 29% to $1.14 billion due to a 22% increase in sales volumes along with a 5% increase in realized commodity prices when compared to the second quarter of 2013. For the six months ended June 30, 2014, crude oil and natural gas revenues totaled $2.14 billion, a 29% increase from the comparable 2013 period due to a 23% increase in sales volumes along with a 5% increase in realized commodity prices. Crude oil represented 87% and 85% of our total crude oil and natural gas revenues for the three and six months ended June 30, 2014, respectively, compared to 88% for both the three and six months ended June 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 six months ended June 30, 2014 were $1.43 billion, a 24% increase from $1.16 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 and realized commodity prices, 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 $4.05 billion, excluding acquisitions. For the six months ended June 30, 2014, we invested approximately $2.1 billion in our capital program, excluding $107.6 million of unbudgeted acquisitions. Our 2014 capital program is focused primarily on increased exploration and development in the Bakken field and the SCOOP play.

Issuance and redemption of senior notes

On May 19, 2014, we issued $1.0 billion of 3.8% Senior Notes due 2024 and $700 million of 4.9% Senior Notes due 2044 and received total net proceeds of approximately $1.68 billion after deducting the initial purchasers' fees.

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 $324.4 million, or 108.12% of par.

We used a portion of the net proceeds from our May 2014 senior note offerings to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of $1.01 billion, and to finance the redemption of our 2019 Notes. The remaining net proceeds from the offerings of approximately $0.3 billion will be used to fund a portion of our 2014 capital program and for general corporate purposes.

New credit facility

On May 16, 2014, we entered into a new unsecured credit facility (the "New Credit Facility") that provides for increased aggregate commitments and an extended maturity beyond the term of our previous credit facility. The New Credit Facility matures on May 16, 2019 and has aggregate commitments totaling $1.75 billion, which may be increased up to $4.0 billion in the future upon agreement between the Company and participating lenders. The New Credit Facility replaced our previous $1.5 billion unsecured credit facility that was due to mature on July 1, 2015. We had no outstanding borrowings and approximately $1.75 billion of unused commitments on our New Credit Facility at June 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).

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 June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Average daily production:				
Crude oil (Bbl per day)	116,441	96,029	111,447	91,077
Natural gas (Mcf per day)	309,074	238,028	292,847	225,467
Crude oil equivalents (Boe per day)	167,953	135,700	160,255	128,655
Average sales prices:				
Crude oil ($/Bbl)	$92.31	$87.22	$91.12	$88.50
Natural gas ($/Mcf)	$5.43	$4.87	$6.20	$4.74
Crude oil equivalents ($/Boe)	$74.09	$70.52	$74.53	$71.02
Crude oil sales price differential to NYMEX ($/Bbl)	$(10.69)	$(7.07)	$(9.90)	$(5.79)
Natural gas sales price premium to NYMEX ($/Mcf)	$0.76	$0.77	$1.41	$1.00
Production expenses ($/Boe)	$5.50	$5.86	$5.62	$5.79
Production taxes (% of oil and gas revenues)	8.3%	8.4%	8.0%	8.3%
DD&A ($/Boe)	$21.28	$18.88	$20.88	$19.27
General and administrative expenses ($/Boe)	$2.08	$2.08	$2.24	$2.17
Non-cash equity compensation ($/Boe)	$0.98	$0.78	$0.91	$0.81
Net income (in thousands)	$103,538	$323,270	$329,772	$463,897
Diluted net income per share	$0.56	$1.75	$1.78	$2.51
EBITDAX (in thousands) (1)	$867,938	$708,107	$1,643,345	$1,329,635

(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, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP. Reconciliations of net income and operating cash flows to EBITDAX are provided subsequently under the heading Non-GAAP Financial Measures.

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

Results of Operations

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

	Three months ended June 30,	
In thousands, except sales price data	2014	2013
Crude oil and natural gas sales	$1,138,085	$884,492
Gain (loss) on derivative instruments, net (1)	(262,524)	199,056
Crude oil and natural gas service operations	10,534	9,509
Total revenues	886,095	1,093,057
Operating costs and expenses	(649,701)	(519,185)
Other expenses, net	(72,048)	(60,744)
Income before income taxes	164,346	513,128
Provision for income taxes	(60,808)	(189,858)
Net income	$103,538	$323,270
Production volumes:		
Crude oil (MBbl) (2)	10,596	8,739
Natural gas (MMcf)	28,126	21,661
Crude oil equivalents (MBoe)	15,284	12,349
Sales volumes:		
Crude oil (MBbl) (2)	10,674	8,932
Natural gas (MMcf)	28,126	21,661
Crude oil equivalents (MBoe)	15,362	12,542
Average sales prices: (3)		
Crude oil ($/Bbl)	$92.31	$87.22
Natural gas ($/Mcf)	5.43	4.87
Crude oil equivalents ($/Boe)	74.09	70.52

(1) Amounts include a non-cash mark-to-market loss on derivatives of $198.4 million for the three months ended June 30, 2014 and a non-cash mark-to-market gain on derivatives of $203.8 million for the three months ended June 30, 2013.

(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 78 MBbls more than crude oil production for the three months ended June 30, 2014 and 193 MBbls more than crude oil production for the three months ended June 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 June 30,				Volume increase	Volume percent increase
	2014		2013			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	10,596	69 %	8,739	71 %	1,857	21 %
Natural gas (MMcf)	28,126	31 %	21,661	29 %	6,465	30 %
Total (MBoe)	15,284	100 %	12,349	100 %	2,935	24 %

	Three months ended June 30,				Volume increase	Volume percent increase
	2014		2013			
	MBoe	Percent	MBoe	Percent		
North Region	11,253	74 %	9,557	77 %	1,696	18 %
South Region	4,031	26 %	2,792	23 %	1,239	44 %

Total	15,284	100	%	12,349	100	%	2,935	24	%

Crude oil production volumes increased 1,857 MBbls, or 21%, for the three months ended June 30, 2014 compared to the three months ended June 30, 2013. Production increases in the Bakken field and SCOOP play contributed incremental production volumes in 2014 of 2,008 MBbls, a 28% increase over production in these areas for the second 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 6,465 MMcf, or 30%, during the three months ended June 30, 2014 compared to the same period in 2013. Natural gas production in the Bakken field increased 1,189 MMcf, or 16%, for the three months ended June 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 7,131 MMcf, or 107%, due to additional wells being completed and producing in the three months ended June 30, 2014 compared to the same period in 2013. These increases were partially offset by decreases in production from non-core 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 June 30, 2014 were $1,138.1 million, a 29% increase from sales of $884.5 million for the same period in 2013. Our sales volumes increased 2,820 MBoe, or 22%, 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 78 MBbls more than crude oil production for the three months ended June 30, 2014 due to changes in transportation availability and pipeline line fill requirements that facilitated the sale of crude oil during the 2014 second quarter that was temporarily stored in inventory at March 31, 2014. We anticipate that our crude oil line fill requirements will increase in the second half of 2014 as new pipelines are put into service for which we have contracted firm capacity. This could result in increased crude oil inventories and reduced sales volumes of approximately 500 MBbls for the second half of 2014, although the impact of such changes may be partially offset by sales of inventory held in storage at June 30, 2014. We expect our line fill obligations will be primarily satisfied in the third quarter of 2014.

Our realized sales price per Boe increased $3.57 to $74.09 for the three months ended June 30, 2014 from $70.52 for the three months ended June 30, 2013. This increase primarily reflects higher prices realized in connection with improved market prices for crude oil and natural gas over 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 second quarter of 2014 was $10.69 compared to $7.07 for the second 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.

Changes in commodity prices during the second quarter of 2014 had a negative impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $262.5 million for the three months ended June 30, 2014. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices.

The following table presents the impact on total revenues related to 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 June 30,	
In thousands	2014	2013
Cash received (paid) on derivatives:		
Crude oil derivatives	$(51,952)	$2,335
Natural gas derivatives	(12,191)	(7,087)
Cash paid on derivatives, net	(64,143)	(4,752)
Non-cash gain (loss) on derivatives:		
Crude oil derivatives	(205,851)	157,880
Natural gas derivatives	7,470	45,928
Non-cash gain (loss) on derivatives, net	(198,381)	203,808
Gain (loss) on derivative instruments, net	$(262,524)	$199,056

The non-cash mark-to-market gains and losses reflected above at June 30, 2014 relate to derivative instruments with various terms that are scheduled to be realized over the period from July 2014 to December 2016. Over this period, actual derivative settlements may differ significantly, either positively or negatively, from the mark-to-market valuation at June 30, 2014.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 15% to $84.5 million for the three months ended June 30, 2014 from $73.4 million for the three months ended June 30, 2013. This increase was primarily the result of an increase in the number of producing wells. Production expense per Boe was $5.50 for the three months ended June 30, 2014 compared to $5.86 per Boe for the three months ended June 30, 2013.

Production taxes and other expenses increased $22.5 million, or 30%, to $97.0 million for the three months ended June 30, 2014 compared to $74.5 million for the three months ended June 30, 2013 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes and higher realized commodity prices. Production taxes as a percentage of crude oil and natural gas revenues were 8.3% for the three months ended June 30, 2014 compared to 8.4% for the three months ended June 30, 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 June 30,	
In thousands	2014	2013
Geological and geophysical costs	$6,732	$5,349
Exploratory dry hole costs	4,473	5,802
Exploration expenses	$11,205	$11,151

Depreciation, Depletion, Amortization and Accretion (“DD&A”). Total DD&A increased $90.1 million, or 38%, to $326.9 million for the second quarter of 2014 compared to $236.8 million for the second quarter of 2013 primarily due to a 22% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Three months ended June 30,	
$/Boe	2014	2013
Crude oil and natural gas	$20.93	$18.61
Other equipment	0.30	0.22
Asset retirement obligation accretion	0.05	0.05
Depreciation, depletion, amortization and accretion	$21.28	$18.88

The increase in DD&A per Boe for the second quarter of 2014 resulted from changes in the mix of well completions over the past year along with an increased use of enhanced completion methods that increase completed well costs. Additionally, certain exploratory wells 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 $11.7 million for the three months ended June 30, 2014 to $51.8 million compared to $40.1 million for the three months ended June 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 $27.5 million for the three months ended June 30, 2014, primarily reflecting fair value adjustments made for certain properties in non-core areas of our South region. Impairment provisions for proved properties amounted to $39.6 million for the three months ended June 30, 2013, primarily reflecting uneconomic results for certain wells drilled in the Niobrara play in Colorado and Wyoming.

General and Administrative Expenses. General and administrative expenses (“G&A”) increased $11.0 million, or 31%, to $46.9 million for the three months ended June 30, 2014 from $35.9 million for the comparable period in 2013. G&A expenses include non-cash charges for equity compensation of $15.0 million and $9.8 million for the three months ended June 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 second quarter of 2014 compared to the second quarter of 2013.

G&A expenses other than equity compensation increased $5.8 million, or 22%, for the three months ended June 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 827 total employees at June 30, 2013 to 1,048 total employees at June 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 June 30,	
$/Boe	2014	2013
General and administrative expenses	$2.08	$2.03
Non-cash equity compensation	0.98	0.78
Corporate relocation expenses	—	0.05
Total general and administrative expenses	$3.06	$2.86

Interest Expense. Interest expense increased $11.4 million, or 19%, to $72.8 million for the three months ended June 30, 2014 compared to $61.4 million for the three months ended June 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 second quarter of 2014 was approximately $5.6 billion with a weighted average interest rate of 5.0% 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 June 30, 2014 of $60.8 million compared to $189.9 million for the three months ended June 30, 2013. We provided for income taxes at a combined federal and state tax rate of approximately 37% for the second quarters of both 2014 and 2013 after taking into account permanent taxable differences.

Six months ended June 30, 2014 compared to the six months ended June 30, 2013

Results of Operations

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

	Six months ended June 30,	
In thousands, except sales price data	2014	2013
Crude oil and natural gas sales	$2,140,418	$1,660,423
Gain (loss) on derivative instruments, net (1)	(302,198)	114,225
Crude oil and natural gas service operations	20,370	21,052
Total revenues	1,858,590	1,795,700
Operating costs and expenses	(1,200,879)	(951,682)
Other expenses, net	(134,264)	(107,673)
Income before income taxes	523,447	736,345
Provision for income taxes	(193,675)	(272,448)
Net income	$329,772	$463,897
Production volumes:		
Crude oil (MBbl) (2)	20,172	16,485
Natural gas (MMcf)	53,005	40,809
Crude oil equivalents (MBoe)	29,006	23,287
Sales volumes:		
Crude oil (MBbl) (2)	19,887	16,577
Natural gas (MMcf)	53,005	40,809
Crude oil equivalents (MBoe)	28,721	23,378
Average sales prices: (3)		
Crude oil ($/Bbl)	$91.12	$88.50
Natural gas ($/Mcf)	6.20	4.74
Crude oil equivalents ($/Boe)	74.53	71.02

(1) Amounts include a non-cash mark-to-market loss on derivatives of $204.8 million for the six months ended June 30, 2014 and a non-cash mark-to-market gain on derivatives of $125.8 million for the six months ended June 30, 2013.

(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 285 MBbls less than crude oil production for the six months ended June 30, 2014 and 92 MBbls more than crude oil production for the six months ended June 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.

	Six months ended June 30,				Volume increase	Volume percent increase
	2014		2013			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	20,172	70 %	16,485	71 %	3,687	22 %
Natural gas (MMcf)	53,005	30 %	40,809	29 %	12,196	30 %
Total (MBoe)	29,006	100 %	23,287	100 %	5,719	25 %

	Six months ended June 30,				Volume increase	Volume percent increase
	2014		2013			
	MBoe	Percent	MBoe	Percent		
North Region	21,371	74 %	17,949	77 %	3,422	19 %

South Region	7,635	26	%	5,338	23	%	2,297	43	%
Total	29,006	100	%	23,287	100	%	5,719	25	%

Crude oil production volumes increased 3,687 MBbls, or 22%, during the six months ended June 30, 2014 compared to the six months ended June 30, 2013. Production increases in the Bakken field and SCOOP play contributed incremental production volumes in 2014 of 3,941 MBbls, a 29% 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.

Natural gas production volumes increased 12,196 MMcf, or 30%, during the six months ended June 30, 2014 compared to the same period in 2013. Natural gas production in the Bakken field increased 2,553 MMcf, or 19%, for the six months ended June 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 13,419 MMcf, or 110%, due to additional wells being completed and producing in the six months ended June 30, 2014 compared to the same period in 2013. These increases were partially offset by decreases in production from non-core 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 six months ended June 30, 2014 were $2,140.4 million, a 29% increase from sales of $1,660.4 million for the same period in 2013. Our sales volumes increased 5,343 MBoe, or 23%, 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 during the first half of 2014, causing crude oil sales volumes to be lower than crude oil production by 285 MBbls. We anticipate that our crude oil line fill requirements will increase in the second half of 2014 as new pipelines are put into service for which we have contracted firm capacity. This could result in increased crude oil inventories and reduced sales volumes of approximately 500 MBbls for the second half of 2014, although the impact of such changes may be partially offset by sales of inventory held in storage at June 30, 2014. We expect our line fill obligations will be primarily satisfied in the third quarter of 2014.

Our realized price per Boe increased $3.51 to $74.53 for the six months ended June 30, 2014 from $71.02 for the six months ended June 30, 2013. This increase primarily reflects higher prices realized in connection with improved market prices for crude oil and natural gas over the prior year.

The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel for the six months ended June 30, 2014 was $9.90 per barrel compared to $5.79 for the six months ended June 30, 2013. We expect volatility in crude oil prices and differentials to continue.

The premium of our realized natural gas sales price per Mcf over NYMEX Henry Hub calendar month average natural gas prices for the six months ended June 30, 2014 was $1.41 compared to $1.00 for the comparable 2013 period. The improved premium reflects an increase in the production and sale of liquids-rich natural gas from our Bakken and SCOOP properties coupled with improved regional market prices for natural gas and natural gas liquids in the 2014 first quarter, particularly in the North region which experienced favorable regional spot market pricing relative to Henry Hub benchmark pricing aided by the impact of winter weather on regional supply and demand. The favorable North region pricing in early 2014 helped the Company realize a sales price premium of $2.14 per Mcf for the first quarter of 2014, which decreased to $0.76 per Mcf for the second quarter of 2014 after the favorable pricing subsided.

Derivatives. Changes in commodity futures price strips during the six months ended June 30, 2014 had a negative impact on the fair value of our derivatives, which resulted in negative revenue adjustments of $302.2 million for the six months ended June 30, 2014. We expect our revenues will continue to be significantly impacted, either positively or negatively, by changes in the fair value of our derivative instruments as a result of volatility in crude oil and natural gas prices. The following table presents the impact on total revenues related to cash and non-cash gains and losses on derivative instruments for the periods presented.

	Six months ended June 30,	
In thousands	2014	2013
Cash received (paid) on derivatives:		
Crude oil derivatives	$(75,059)	$(7,133)
Natural gas derivatives	(22,348)	(4,429)
Cash paid on derivatives, net	(97,407)	(11,562)
Non-cash gain (loss) on derivatives:		
Crude oil derivatives	(186,878)	110,754
Natural gas derivatives	(17,913)	15,033
Non-cash gain (loss) on derivatives, net	(204,791)	125,787
Gain (loss) on derivative instruments, net	$(302,198)	$114,225

The non-cash mark-to-market losses reflected above at June 30, 2014 relate to derivative instruments with various terms that are scheduled to be realized over the period from July 2014 to December 2016. Over this period, actual derivative settlements may differ significantly, either positively or negatively, from the mark-to-market valuation at June 30, 2014.

Operating Costs and Expenses

Production Expenses and Production Taxes and Other Expenses. Production expenses increased 19% to $161.4 million during the six months ended June 30, 2014 from $135.2 million during the six months ended June 30, 2013. This increase is primarily the result of an increase in the number of producing wells. Production expense per Boe was $5.62 for the six months ended June 30, 2014 compared to $5.79 per Boe for the six months ended June 30, 2013. Production taxes and other expenses increased $35.9 million, or 26%, to $175.3 million during the six months ended June 30, 2014 compared to $139.4 million for the six months ended June 30, 2013 primarily as a result of higher crude oil and natural gas revenues resulting from increased sales volumes and higher realized commodity prices. Production taxes as a percentage of crude oil and natural gas revenues were 8.0% for the six months ended June 30, 2014 compared to 8.3% for the six months ended June 30, 2013. The decrease was due to significant growth over the past year in our SCOOP operations and resulting increase in taxable revenues coming 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.

	Six months ended June 30,	
In thousands	2014	2013
Geological and geophysical costs	$11,635	$12,902
Exploratory dry hole costs	4,383	8,063
Exploration expenses	$16,018	$20,965

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $149.2 million, or 33%, to $599.7 million for the six months ended June 30, 2014 compared to $450.5 million for the same period in 2013 primarily due to a 23% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Six months ended June 30,	
$/Boe	2014	2013
Crude oil and natural gas	$20.53	$18.99
Other equipment	0.29	0.22
Asset retirement obligation accretion	0.06	0.06
Depreciation, depletion, amortization and accretion	$20.88	$19.27

The increase in DD&A per Boe for the six months ended June 30, 2014 resulted from changes in the mix of well completions over the past year along with an increased use of enhanced completion methods that increase completed well costs. Additionally, certain exploratory wells resulted in more expensive reserve additions. These factors contributed to an increase in DD&A on a per-Boe basis over the prior period.

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Property Impairments. Property impairments increased in the six months ended June 30, 2014 by $17.7 million to $137.5 million compared to $119.8 million for the six months ended June 30, 2013.

Impairments of non-producing properties increased $26.0 million during the six months ended June 30, 2014 to $106.2 million compared to $80.2 million for the six months ended June 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 $31.3 million for the six months ended June 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 six months ended June 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 $20.8 million, or 30%, to $90.5 million for the six months ended June 30, 2014 from $69.7 million for the comparable period in 2013. G&A expenses include non-cash charges for equity compensation of $26.0 million and $19.0 million for the six months ended June 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 six months ended June 30, 2014 compared to the six months ended June 30, 2013.

G&A expenses other than equity compensation increased $13.8 million, or 27%, for the six months ended June 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.

	Six months ended June 30,	
$/Boe	2014	2013
General and administrative expenses	$2.24	$2.11
Non-cash equity compensation	0.91	0.81
Corporate relocation expenses	—	0.06
Total general and administrative expenses	$3.15	$2.98

Interest Expense. Interest expense increased $26.9 million, or 25%, to $135.8 million for the six months ended June 30, 2014 compared to $108.9 million for the six months ended June 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 six months ended June 30, 2014 was approximately $5.3 billion with a weighted average interest rate of 5.0% compared to a weighted average outstanding long-term debt balance of $4.1 billion and a weighted average interest rate of 5.1% 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 six months ended June 30, 2014 of $193.7 million compared to $272.4 million for the six months ended June 30, 2013. We provided for income taxes at a combined federal and state tax rate of approximately 37% for both the six months ended June 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 June 30, 2014, we had $777.0 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 June 30, 2014. As of August 1, 2014, cash and cash equivalents had decreased due to the July 11, 2014 redemption of our $300 million of 8.25% Senior Notes due 2019 for $324.4 million and 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 $1.43 billion and $1.16 billion for the six months ended June 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 and realized commodity prices, 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 six months ended June 30, 2014 and 2013, we had cash flows used in investing activities (excluding proceeds from asset sales) of $2.12 billion and $1.85 billion, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Cash acquisition capital expenditures totaled $107.6 million and $122.7 million for the six months ended June 30, 2014 and 2013, respectively. Cash capital expenditures excluding acquisitions totaled $2.01 billion and $1.73 billion for the six months ended June 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 six months ended June 30, 2014 was partially offset by proceeds received from asset dispositions. Proceeds from the sale of assets amounted to $39.0 million during the six months ended June 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.

Cash flows from financing activities

Net cash provided by financing activities for the six months ended June 30, 2014 was $1.39 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 (the "2024 Notes") and $700 million of 4.9% Senior Notes due 2044 (the "2044 Notes") in May 2014, partially offset by net repayments of $275 million on our credit facility.

Net cash provided by financing activities for the six months ended June 30, 2013 was $877.9 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, assuming sustained strength in commodity prices and successful implementation of our business strategy, we believe funds from operating cash flows, our remaining cash balance, and our credit facility, including our ability to increase our borrowing capacity thereunder, should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments for the next 12 months. We may choose to access the capital markets for additional financing to take advantage of business opportunities that may arise if such financing can be arranged at favorable terms.

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

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 in the future 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 June 30, 2014. On May 19, 2014, we issued $1.0 billion of 2024 Notes and $700 million of 2044 Notes and received total net proceeds of $1.68 billion after deducting the initial purchasers’ fees. A portion of the net proceeds was used to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of approximately $1.01 billion. As of August 1, 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 June 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.

The commitments under our credit facility are from a syndicate of 15 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. If one or more lenders is unable or unwilling to fund its commitment, we would not have the full availability of the $1.75 billion commitment.

If we are unable to access funding on acceptable terms when needed, we may not be able to fully implement our business plans, complete new property acquisitions to replace our reserves, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Proceeds from issuance of long-term debt

We used a portion of the $1.68 billion of net proceeds from our May 2014 issuances of 2024 Notes and 2044 Notes to repay all borrowings then outstanding under our credit facility, which had a balance prior to payoff of approximately $1.01 billion, and to finance the redemption of our $300 million of 8.25% Senior Notes due 2019 as discussed below. The remaining net proceeds from the issuances of approximately $0.3 billion will be used to fund a portion of our 2014 capital budget and for general corporate purposes.

Future Capital Requirements

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 $324.4 million, or 108.12% of par, using a portion of the proceeds from our May 2014 issuances of 2024 Notes and 2044 Notes.

Our remaining long-term debt includes outstanding senior note obligations totaling $5.8 billion at August 1, 2014. Scheduled maturities of our remaining 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 June 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.

Our capital expenditures budget for 2014 is $4.05 billion excluding acquisitions, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$3,540
Land costs	300
Capital facilities, workovers and other corporate assets	180
Seismic	30
Total 2014 capital budget, excluding acquisitions	$4,050

During the six months ended June 30, 2014, we participated in the completion of 486 gross (196 net) wells and invested approximately $2,127.8 million in our capital program, excluding $107.6 million of unbudgeted acquisitions and including $5.3 million of seismic costs and $116.0 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	$ 1,882.5
Land costs	147.4
Capital facilities, workovers and other corporate assets	92.6
Seismic	5.3
Capital expenditures, excluding acquisitions	2,127.8
Acquisitions of producing properties	33.6
Acquisitions of non-producing properties	74.0
Total acquisitions	107.6
Total capital expenditures	$ 2,235.4

Our 2014 capital program is focused primarily on increased exploration and development in the Bakken field of North Dakota and Montana and the SCOOP play in south-central Oklahoma.

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 June 30, 2014. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of June 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 June 30, 2014 total approximately $335 million, of which $64 million is expected to be incurred in the remainder of 2014, $92 million in 2015, $86 million in 2016, $65 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 2024, require the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of June 30, 2014 under the operational pipeline transportation arrangements amount to approximately $91 million, of which $10 million is expected to be incurred in the remainder of 2014, $20 million in 2015, $16 million in 2016, $11 million in 2017, $6 million in 2018, and $28 million thereafter.

Further, we are a party to additional firm transportation commitments for future crude oil and natural gas pipeline projects being considered for development that are not yet operational. Such projects require the granting of regulatory approvals or otherwise require additional construction efforts by counterparties before being completed. Future commitments under the non-operational arrangements total approximately $1.2 billion at June 30, 2014, representing aggregate transportation charges expected to be incurred over the terms of the arrangements assuming the proposed pipeline projects are completed and become 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 these non-operational arrangements cannot be predicted with certainty and may not be incurred on a ratable basis over a calendar year or may not be incurred at all. Although timing is uncertain, operators have indicated that certain pipeline projects may become operational in the fourth quarter of 2014 and first half of 2015, which, if accurate, would obligate us for transportation charges totaling $36 million in 2014, $160 million in

2015, $168 million annually in years 2016 through 2018, and $206 million thereafter.

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 June 30, 2014 total approximately $16 million, of which $6 million is expected to be incurred in 2014, $8 million in 2015, and $2 million in 2016.

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

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our Form 10-K for the year ended December 31, 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 currently 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, and non-cash equity compensation expense. EBITDAX is not a measure of net income or operating cash flows as determined by U.S. GAAP.

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. 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.

	Three months ended June 30,		Six months ended June 30,	
In thousands	2014	2013	2014	2013
Net income	$103,538	$323,270	$329,772	$463,897
Interest expense	72,841	61,378	135,816	108,853
Provision for income taxes	60,808	189,858	193,675	272,448
Depreciation, depletion, amortization and accretion	326,871	236,790	599,732	450,468
Property impairments	79,316	79,712	137,524	119,793
Exploration expenses	11,205	11,151	16,018	20,965
Impact from derivative instruments:				
Total (gain) loss on derivatives, net	262,524	(199,056)	302,198	(114,225)
Total cash paid on derivatives, net	(64,143)	(4,752)	(97,407)	(11,562)
Non-cash (gain) loss on derivatives, net	198,381	(203,808)	204,791	(125,787)
Non-cash equity compensation	14,978	9,756	26,017	18,998
EBITDAX	$867,938	$708,107	$1,643,345	$1,329,635

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

	Six months ended June 30,	
In thousands	2014	2013
Net cash provided by operating activities	$1,432,453	$1,156,945
Current income tax provision	3,104	5,830
Interest expense	135,816	108,853
Exploration expenses, excluding dry hole costs	11,635	12,902
Gain (loss) on sale of assets, net	(6,363)	(213)
Other, net	(11,317)	(637)
Changes in assets and liabilities	78,017	45,955
EBITDAX	$1,643,345	$1,329,635

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ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

General. We are exposed to a variety of market risks including commodity price risk, credit risk and interest rate risk. We address these risks through a program of risk management which may include the use of derivative instruments.

Commodity Price Risk. Our primary market risk exposure is in the pricing applicable to our crude oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for crude oil and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the six months ended June 30, 2014, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $407 million for each $10.00 per barrel change in crude oil prices and $107 million for each $1.00 per Mcf change in natural gas prices.

To reduce price risk caused by these market fluctuations, we 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. While hedging limits the downside risk of adverse price movements, it also limits future revenues from upward price movements.

Changes in commodity prices during the six months ended June 30, 2014 had an overall negative impact on the fair value of our derivative instruments. For the six months ended June 30, 2014, we recognized cash losses on derivatives of $97.4 million and reported a non-cash mark-to-market loss on derivatives of $204.8 million. The fair value of our derivative instruments at June 30, 2014 was a net liability of $299.5 million. The mark-to-market net liability relates to derivative instruments with various terms that are scheduled to mature over the period from July 2014 through December 2016. Over this period, actual derivative settlements may differ significantly, either positively or negatively, from the mark-to-market valuation at June 30, 2014. An assumed increase in the forward commodity prices used in the June 30, 2014 valuation of our derivative instruments of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would increase our net derivative liability to approximately $813 million at June 30, 2014. Conversely, an assumed decrease in forward commodity prices of $10.00 per barrel for crude oil and $1.00 per MMBtu for natural gas would change our derivative valuation to a net asset of approximately $210 million at June 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 ($761 million in receivables at June 30, 2014), our joint interest receivables ($387 million at June 30, 2014), and counterparty credit risk associated with our derivative instrument receivables ($0.5 million at June 30, 2014).

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 $56.2 million at June 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. All of our derivative contracts are with parties that are lenders (or affiliates of lenders) under our credit facility.

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to any variable-rate borrowings we may have outstanding from time to time under our credit facility. We manage our interest rate exposure by monitoring both the effects of market changes in interest rates and the proportion of our debt portfolio that is variable-rate versus fixed-rate debt.

We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives may be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We currently have no interest rate derivatives. We had no outstanding borrowings on our credit facility at August 1, 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 June 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 June 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 six months ended June 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 June 30, 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 (2)
April 1, 2014 to April 30, 2014	—		—		—	—
May 1, 2014 to May 31, 2014	57,295	(1)	$134.45	(1)	—	—
June 1, 2014 to June 30, 2014	—		—		—	—
Total	57,295		$134.45		—	—

(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. Of the amount above, 14,995 shares represent shares surrendered by employees to cover tax liabilities at an average price per share of $134.42. 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. Additionally, the amount above includes 42,300 shares of our common stock purchased by Harold G. Hamm, our Chairman, Chief Executive Officer, and controlling shareholder in open-market transactions on May 20, 2014 at an average price per share of $134.46.

(2) 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:	August 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.
4.1	Indenture dated as of May 19, 2014 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Wilmington Trust, National Association, as trustee, filed as Exhibit 4.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 22, 2014 and incorporated herein by reference.
4.2	Registration Rights Agreement dated as of May 19, 2014 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated as representative of the several initial purchasers filed as Exhibit 4.2 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 22, 2014 and incorporated herein by reference.
10.1	Purchase Agreement dated as of May 12, 2014 among Continental Resources, Inc., Banner Pipeline Company, L.L.C., CLR Asset Holdings, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated as representative of the several initial purchasers filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 13, 2014 and incorporated herein by reference.
10.2	Revolving Credit Agreement dated as of May 16, 2014 among Continental Resources, Inc., as borrower, Banner Pipeline Company L.L.C. and CLR Asset Holdings, LLC, as guarantors, Union Bank, N.A., as administrative agent, and the other lenders party thereto filed as Exhibit 10.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed May 21, 2014 and incorporated herein by reference.
10.3†	Second Amendment to the Continental Resources, Inc. Deferred Compensation Plan adopted and effective as of May 23, 2014 filed as Exhibit 10.15 to the Company's Registration Statement on Form S-4 (Commission File No. 333-196944) filed June 20, 2014 and incorporated herein by reference.
10.4†	Summary of Non-Employee Director Compensation Approved as of May 23, 2014 to be effective July 1, 2014 filed as Exhibit 10.16 to the Company's Registration Statement on Form S-4 (Commission File No. 333-196944) filed June 20, 2014 and incorporated herein by reference.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (15 U.S.C. Section 7241).
32**	Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
101.INS**	XBRL Instance Document

101.SCH** XBRL Taxonomy Extension Schema Document

101.CAL** XBRL Taxonomy Extension Calculation Linkbase Document

101.DEF** XBRL Taxonomy Extension Definition Linkbase Document

101.LAB** XBRL Taxonomy Extension Label Linkbase Document

101.PRE** XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

** Furnished herewith

† Management contract or compensatory plan or arrangement filed pursuant to Item 601(b)(10)(iii) of Regulation S-K.