CONTINENTAL RESOURCES, INC
Form 10-Q
November 04, 2015
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2015

or

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

For the transition period from to

Commission File Number: 001-32886

CONTINENTAL RESOURCES, INC.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

373,008,223 shares of our $0.01 par value common stock were outstanding on October 31, 2015.

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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.
“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 crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.
“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.
“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.
“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.
“royalty interest” Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.
“SCOOP” Refers to the South Central Oklahoma Oil Province, a term we use to describe an area of crude oil and liquids-rich natural gas properties located in the Anadarko basin of Oklahoma in which we operate.
"STACK" Refers to Sooner Trend Anadarko Canadian Kingfisher, a term used to describe a play located in the Anadarko Basin of Oklahoma in which we operate.
“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 and information incorporated by reference in this report include “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, forecasts or expectations regarding the Company's business and statements or information concerning the Company’s future operations, performance, financial condition, production and reserves, schedules, plans, timing of development, rates of return, budgets, costs, business strategy, objectives, and cash flows, included in this report are forward-looking statements. The words “could,” “may,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “budget,” “plan,” “continue,” “potential,” “guidance,” similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include, but are not limited to, statements about:

- our business and financial strategy;
- our future operations;
- our crude oil and natural gas reserves and related development plans;
- our technology;
- 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;
- property 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;
- 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.

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 these assumptions and expectations are reasonable, they are inherently subject to numerous business, economic, competitive, regulatory and other risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company's control. No assurance can be given that such expectations will be correct or achieved or that the assumptions are accurate. The risks and uncertainties that may affect the operations, performance and results of the business and forward-looking statements include, but are not limited to, those risk factors and other cautionary statements described under Part II, Item 1A. Risk Factors and elsewhere in this report, if any, our Annual Report on Form 10-K for the year ended December 31, 2014, registration statements filed from time to time with the Securities and Exchange Commission, 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 on which such statement is made. Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, the Company's 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.

Except as expressly stated above or otherwise required by applicable law, the Company undertakes no obligation to publicly correct or update any forward-looking statement whether as a result of new information, future events or circumstances after the date of this report, or otherwise.

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

In thousands, except par values and share data	September 30, 2015 (Unaudited)	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$16,955	$24,381
Receivables:		
Crude oil and natural gas sales	429,350	552,476
Affiliated parties	104	13,360
Joint interest and other, net	355,250	567,476
Derivative assets	78,610	52,423
Inventories	93,010	102,179
Deferred and prepaid taxes	2,137	63,266
Prepaid expenses and other	11,492	14,040
Total current assets	986,908	1,389,601
Net property and equipment, based on successful efforts method of accounting	14,173,563	13,635,852
Noncurrent derivative assets	27,271	31,992
Other noncurrent assets	18,135	18,588
Total assets	$15,205,877	$15,076,033
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable trade	$613,780	$1,263,724
Revenues and royalties payable	227,724	272,755
Payables to affiliated parties	482	7,305
Accrued liabilities and other	305,705	404,506
Derivative liabilities	99	1,645
Current portion of long-term debt	2,127	2,078
Total current liabilities	1,149,917	1,952,013
Long-term debt, net of current portion	7,108,702	5,926,800
Other noncurrent liabilities:		
Deferred income tax liabilities	2,048,413	2,141,447
Asset retirement obligations, net of current portion	84,179	75,462
Noncurrent derivative liabilities	110	3,109
Other noncurrent liabilities	15,979	9,358
Total other noncurrent liabilities	2,148,681	2,229,376
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; 1,000,000,000 shares authorized; 372,968,752 shares issued and outstanding at September 30, 2015; 372,005,502 shares issued and outstanding at December 31, 2014	3,730	3,720
Additional paid-in capital	1,335,574	1,287,941
Accumulated other comprehensive loss	(3,303)	(385)

Retained earnings	3,462,576	3,676,568
Total shareholders' equity	4,798,577	4,967,844
Total liabilities and shareholders' equity	$15,205,877	$15,076,033

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 Comprehensive Income (Loss)

	Three months ended September 30,		Nine months ended September 30,	
In thousands, except per share data	2015	2014	2015	2014
Revenues				
Crude oil and natural gas sales	$628,457	$1,138,460	$1,999,751	$3,223,605
Crude oil and natural gas sales to affiliates	—	21,821	1,400	77,094
Gain on derivative instruments, net	46,527	473,999	74,545	171,801
Crude oil and natural gas service operations	7,685	11,048	28,991	31,418
Total revenues	682,669	1,645,328	2,104,687	3,503,918
Operating costs and expenses				
Production expenses	84,036	95,700	267,058	255,911
Production expenses to affiliates	—	1,674	1,654	2,870
Production taxes and other expenses	47,682	97,399	157,589	272,726
Exploration expenses	232	13,514	14,680	29,532
Crude oil and natural gas service operations	4,059	4,337	15,045	18,390
Depreciation, depletion, amortization and accretion	448,809	363,677	1,288,278	963,409
Property impairments	96,697	85,561	321,130	223,085
General and administrative expenses	53,798	43,980	143,368	134,435
(Gain) loss on sale of assets, net	(288)	(5,411)	(22,930)	952
Total operating costs and expenses	735,025	700,431	2,185,872	1,901,310
Income (loss) from operations	(52,356)	944,897	(81,185)	1,602,608
Other income (expense):				
Interest expense	(79,399)	(73,912)	(232,904)	(209,728)
Loss on extinguishment of debt	—	(24,517)	—	(24,517)
Other	588	393	1,474	1,945
	(78,811)	(98,036)	(231,430)	(232,300)
Income (loss) before income taxes	(131,167)	846,861	(312,615)	1,370,308
Provision (benefit) for income taxes	(48,744)	313,340	(98,623)	507,015
Net income (loss)	$(82,423)	$533,521	$(213,992)	$863,293
Basic net income (loss) per share	$(0.22)	$1.45	$(0.58)	$2.34
Diluted net income (loss) per share	$(0.22)	$1.44	$(0.58)	$2.33
Comprehensive income (loss):				
Net income (loss)	$(82,423)	$533,521	$(213,992)	$863,293
Other comprehensive loss, net of tax:				
Foreign currency translation adjustments	(438)	—	(2,918)	—
Total other comprehensive loss, net of tax	(438)	—	(2,918)	—
Comprehensive income (loss)	$(82,861)	$533,521	$(216,910)	$863,293

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

Continental Resources, Inc. and Subsidiaries
Condensed Consolidated Statement of Shareholders' Equity

In thousands, except share data	Shares outstanding	Common stock	Additional paid-in capital	Accumulated other comprehensive loss	Retained earnings	Total shareholders' equity
Balance at December 31, 2014	372,005,502	$3,720	$1,287,941	$ (385)	$3,676,568	$4,967,844
Net loss (unaudited)	—	—	—	—	(213,992)	(213,992)
Other comprehensive loss, net of tax (unaudited)	—	—	—	(2,918)	—	(2,918)
Stock-based compensation (unaudited)	—	—	40,273	—	—	40,273
Excess tax benefit from stock-based compensation (unaudited)	—	—	13,177	—	—	13,177
Restricted stock:						
Granted (unaudited)	1,383,557	14	—	—	—	14
Repurchased and canceled (unaudited)	(128,308)	(1)	(5,817)	—	—	(5,818)
Forfeited (unaudited)	(291,999)	(3)	—	—	—	(3)
Balance at September 30, 2015 (unaudited)	372,968,752	$3,730	$1,335,574	$ (3,303)	$3,462,576	$4,798,577

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

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

	Nine months ended September 30,	
In thousands	2015	2014
Cash flows from operating activities		
Net income (loss)	$(213,992)	$863,293
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	1,286,158	970,273
Property impairments	321,130	223,085
Non-cash gain on derivatives, net	(26,011)	(269,018)
Stock-based compensation	40,290	39,419
Provision (benefit) for deferred income taxes	(98,645)	504,737
Excess tax benefit from stock-based compensation	(13,177)	—
Dry hole costs	8,183	9,142
(Gain) loss on sale of assets, net	(22,930)	952
Loss on extinguishment of debt	—	24,517
Other, net	10,143	5,986
Changes in assets and liabilities:		
Accounts receivable	351,309	(192,178)
Inventories	9,137	(28,124)
Other current assets	64,271	(7,017)
Accounts payable trade	(178,000)	82,297
Revenues and royalties payable	(45,030)	32,500
Accrued liabilities and other	(78,947)	16,645
Other noncurrent assets and liabilities	1,603	1,342
Net cash provided by operating activities	1,415,492	2,277,851
Cash flows from investing activities		
Exploration and development	(2,598,367)	(3,255,327)
Purchase of producing crude oil and natural gas properties	(557)	(48,305)
Purchase of other property and equipment	(31,991)	(51,974)
Proceeds from sale of assets	33,216	129,346
Net cash used in investing activities	(2,597,699)	(3,226,260)
Cash flows from financing activities		
Credit facility borrowings	1,780,000	1,105,000
Repayment of credit facility	(600,000)	(1,380,000)
Proceeds from issuance of Senior Notes	—	1,681,834
Redemption of Senior Notes	—	(300,000)
Premium on redemption of Senior Notes	—	(17,497)
Repayment of other debt	(1,552)	(1,503)
Debt issuance costs	(2,110)	(7,999)
Repurchase of restricted stock for tax withholdings	(5,818)	(7,618)
Excess tax benefit from stock-based compensation	13,177	—
Net cash provided by financing activities	1,183,697	1,072,217
Effect of exchange rate changes on cash	(8,916)	—
Net change in cash and cash equivalents	(7,426)	123,808
Cash and cash equivalents at beginning of period	24,381	28,482

Cash and cash equivalents at end of period	$16,955	$152,290

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 primarily located 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 68% of the Company's crude oil and natural gas production and 77% of its crude oil and natural gas revenues for the nine months ended September 30, 2015. The Company's principal producing properties in the North region are located in the Bakken field of North Dakota and Montana. In recent years, the Company has significantly expanded its activity in the South region with its discovery and announcement of the SCOOP play in Oklahoma. The South region now comprises 32% of the Company's crude oil and natural gas production and 23% of its crude oil and natural gas revenues for the nine months ended September 30, 2015.

The Company has focused its operations on the exploration and development of crude oil since the 1980s. For the nine months ended September 30, 2015, crude oil accounted for 67% of the Company's total production and 86% 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. 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 Quarterly Report on Form 10-Q ("Form 10-Q") together with the Company's Annual Report on Form 10-K for the year ended December 31, 2014 ("2014 Form 10-K"), which includes a summary of the Company's significant accounting policies and other disclosures.

The condensed consolidated financial statements as of September 30, 2015 and for the three and nine month periods ended September 30, 2015 and 2014 are unaudited. The condensed consolidated balance sheet as of December 31, 2014 was derived from the audited balance sheet included in the 2014 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.

Earnings per share

Basic net income (loss) per share is computed by dividing net income (loss) by the weighted-average number of shares outstanding for the period. Diluted net income (loss) 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

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weighted average shares outstanding and net income (loss) per share for the three and nine months ended September 30, 2015 and 2014.

	Three months ended September 30,		Nine months ended September 30,	
In thousands, except per share data	2015	2014	2015	2014
Income (loss) (numerator):				
Net income (loss) - basic and diluted	$(82,423)	$533,521	$(213,992)	$863,293
Weighted average shares (denominator):				
Weighted average shares - basic	369,599	368,814	369,499	368,740
Non-vested restricted stock (1)	—	1,714	—	1,892
Weighted average shares - diluted	369,599	370,528	369,499	370,632
Net income (loss) per share:				
Basic	$(0.22)	$1.45	$(0.58)	$2.34
Diluted	$(0.22)	$1.44	$(0.58)	$2.33

(1) The potential dilutive effect of approximately 688,800 and 1,521,000 weighted average restricted shares were not included in the calculation of diluted net loss per share for the three and nine months ended September 30, 2015, respectively, because to do so would have been anti-dilutive.

Inventories

Inventory is comprised of crude oil held in storage or as line fill in pipelines and tubular goods and equipment to be used in the Company's exploration and development activities. Crude oil inventories are valued at the lower of cost or market primarily using the first-in, first-out inventory method. Tubular goods and equipment are valued at the lower of cost or market, with cost determined primarily using a weighted average cost method applied to specific classes of inventory items.

The components of inventory as of September 30, 2015 and December 31, 2014 consisted of the following:

In thousands	September 30, 2015	December 31, 2014
Tubular goods and equipment	$15,936	$15,659
Crude oil	77,074	86,520
Total	$93,010	$102,179

Income taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at period-end. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized. The Company recorded valuation allowances of $0.9 million and $13.3 million for the three and nine months ended September 30, 2015, respectively, against deferred tax assets associated with operating loss carryforwards generated by its Canadian subsidiary in 2015 for which the Company does not expect to realize a benefit.

Affiliate transactions

The affiliate transactions reflected in the accompanying unaudited condensed consolidated statements of comprehensive income (loss) include transactions between the Company and Hiland Partners, LP and its subsidiaries ("Hiland"). Hiland was controlled by the Company's principal shareholder through February 13, 2015, at which time it was sold to an unaffiliated third party. As a result of the sale, the prior related party relationship between the Company and Hiland terminated as of February 13, 2015, which resulted in a reduction in affiliate transactions recognized in the Company's financial statements at September 30, 2015 and for the three and nine months then ended.

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

Adoption of new accounting pronouncement

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). The new standard requires debt issuance costs related to a recognized term debt liability, such as the Company's senior notes and note payable, be presented in the balance sheet as a direct deduction from the carrying amount of that term debt liability, consistent with the presentation of a debt discount. Under previous guidance, debt issuance costs were required to be presented in the balance sheet as an asset. The new standard does not affect the existing recognition and measurement guidance for debt issuance costs. The new standard is effective for annual and interim periods beginning after December 15, 2015, with early adoption permitted.

The Company early adopted ASU 2015-03 as of June 30, 2015 on a retrospective basis to all prior balance sheet periods presented. As a result of the adoption, the Company reclassified unamortized debt issuance costs associated with its senior notes and note payable, which totaled $65.7 million and $69.0 million as of June 30, 2015 and December 31, 2014, respectively, from "Other noncurrent assets" to a reduction of "Long-term debt, net of current portion" on the condensed consolidated balance sheets. Unamortized debt issuance costs reflected as a reduction of long-term debt subsequently totaled $64.0 million as of September 30, 2015. Adoption of ASU 2015-03 had no impact on the Company's current and previously reported shareholders' equity, results of operations, or cash flows. The December 31, 2014 carrying amounts for the Company's senior notes and note payable presented throughout this report on Form 10-Q have been adjusted to reflect the retroactive adoption of ASU 2015-03. Unamortized debt issuance costs associated with the Company's credit facility, which amounted to $7.6 million and $7.0 million as of September 30, 2015 and December 31, 2014, respectively, have not been reclassified and remain reflected in "Other noncurrent assets" on the condensed consolidated balance sheets.

Note 3. Supplemental Cash Flow Information

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

	Nine months ended September 30,	
In thousands	2015	2014
Supplemental cash flow information:		
Cash paid for interest	$204,180	$173,057
Cash paid for income taxes	27	4,012
Cash received for income tax refunds	59,117	5
Non-cash investing activities:		
Increase (decrease) in accrued capital expenditures	(482,475)	235,431
Asset retirement obligation additions and revisions, net	6,267	6,232

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 comprehensive income (loss) under the caption “Gain on derivative instruments, net.”

The Company may utilize swap and collar derivative contracts to economically hedge against the variability in cash flows associated with the 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, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price. 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.

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The Company’s derivative contracts are settled based upon reported settlement prices on commodity exchanges. Crude oil derivative settlements are based on NYMEX West Texas Intermediate (“WTI”) pricing or Inter-Continental Exchange (“ICE”) pricing for Brent crude oil. Natural gas derivative settlements are 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 and written call options, volatility, the risk-free interest rate, and the time to expiration. The calculation of the fair value of collars and written call options requires the use of an option-pricing model. See Note 5. Fair Value Measurements.

At September 30, 2015, the Company had outstanding derivative contracts with respect to future production as set forth in the tables below.

Crude Oil - NYMEX WTI		Ceilings	
Period and Type of Contract	Bbls	Range	Weighted Average Price
October 2015 - December 2015			
Written call options - WTI (1)	1,104,000	$95.85 - $103.75	$98.36

Crude Oil - ICE Brent		Ceilings	
Period and Type of Contract	Bbls	Range	Weighted Average Price
October 2015 - December 2015			
Written call options - ICE Brent (1)	184,000	$107.40	$107.40
January 2016 - December 2016			
Written call options - ICE Brent (1)	1,464,000	$107.70	$107.70

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
October 2015 - December 2015						
Swaps - Henry Hub	9,780,000	$3.37				
Collars - Henry Hub	7,360,000		$3.50 - $3.75	$3.69	$4.89 - $5.48	$5.04
January 2016 - December 2016						
Swaps - Henry Hub	75,930,000	$3.85				
January 2017 - December 2017						
Swaps - Henry Hub	25,550,000	$3.35				
Collars - Henry Hub	7,300,000		$3.00	$3.00	$3.88	$3.88

(1) Written call options represent the ceiling positions remaining from the Company's previous crude oil collar contracts. The floor positions of the collars were liquidated in the fourth quarter of 2014. For these written call options, the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price.

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Derivative gains and losses

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

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2015	2014	2015	2014
Cash received (paid) on derivatives:				
Crude oil fixed price swaps	$—	$(4,126)	$—	$(77,148)
Crude oil collars	—	(233)	—	(2,270)
Natural gas fixed price swaps	5,142	4,549	29,084	(17,799)
Natural gas collars	6,775	—	19,450	—
Cash received (paid) on derivatives, net	11,917	190	48,534	(97,217)
Non-cash gain (loss) on derivatives:				
Crude oil fixed price swaps	—	416,637	—	228,845
Crude oil collars	—	27,386	—	28,300
Crude oil written call options	617	—	4,544	—
Natural gas fixed price swaps	36,257	25,851	33,453	7,944
Natural gas collars	(2,264)	3,935	(11,986)	3,929
Non-cash gain on derivatives, net	34,610	473,809	26,011	269,018
Gain on derivative instruments, net	$46,527	$473,999	$74,545	$171,801

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	September 30, 2015	December 31, 2014
Commodity derivative assets:		
Gross amounts of recognized assets	$105,881	$84,415
Gross amounts offset on balance sheet	—	—
Net amounts of assets on balance sheet	105,881	84,415
Commodity derivative liabilities:		
Gross amounts of recognized liabilities	(209)	(4,770)
Gross amounts offset on balance sheet	—	16
Net amounts of liabilities on balance sheet	$(209)	$(4,754)

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

In thousands	September 30, 2015	December 31, 2014
Derivative assets	$78,610	$52,423
Noncurrent derivative assets	27,271	31,992
Net amounts of assets on balance sheet	105,881	84,415
Derivative liabilities	(99)	(1,645)
Noncurrent derivative liabilities	(110)	(3,109)
Net amounts of liabilities on balance sheet	(209)	(4,754)
Total derivative assets, net	$105,672	$79,661

Note 5. Fair Value Measurements

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

- Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
- Level 2: Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.
- Level 3: Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management’s best estimate of fair value.

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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 collars and written call options requires the use of an industry-standard option pricing model that considers various inputs including quoted forward commodity prices, 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.

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The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of September 30, 2015 and December 31, 2014.

	Fair value measurements at September 30, 2015 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$96,052	$—	$96,052
Collars	—	9,829	—	9,829
Written call options	—	(209)	—	(209)
Total	$—	$105,672	$—	$105,672

	Fair value measurements at December 31, 2014 using:			
In thousands	Level 1	Level 2	Level 3	Total
Derivative assets (liabilities):				
Fixed price swaps	$—	$62,599	$—	$62,599
Collars	—	21,816	—	21,816
Written call options	—	(4,754)	—	(4,754)
Total	$—	$79,661	$—	$79,661

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. 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 the Company's estimates of future crude oil and natural gas production, commodity prices based on commodity futures price strips, operating 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 strip prices through 2019 (adjusted for differentials), escalating 3% per year thereafter
Operating 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 three and nine month periods ended September 30, 2015 and September 30, 2014, 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 $36.3 million and $111.3 million for the three and nine months ended September 30, 2015, respectively, resulting from declines in commodity prices that indicated the carrying amounts for certain fields were not recoverable. The 2015 year to date impairments reflect fair value adjustments primarily concentrated in an emerging area with minimal production and costly reserve additions

($42.5 million, including $1.3 million in the third quarter), the Buffalo Red River units ($26.3 million, all in the third quarter), the Medicine Pole Hills units ($22.9 million, including $8.2 million in the third quarter), various non-core areas in the South region ($11.4 million, including $0.4 million in the third

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quarter), and non-Bakken areas of North Dakota and Montana ($8.2 million, including $0.1 million in the third quarter). The impaired properties were written down to their estimated fair value totaling approximately $48.5 million. Impairments of proved properties totaled $38.0 million and $69.3 million for the three and nine months ended September 30, 2014, respectively, which primarily reflected fair value adjustments made for certain properties in non-core areas of the South region. The impaired properties were written down to their estimated fair value totaling approximately $15.4 million as of September 30, 2014.

Certain unproved crude oil and natural gas properties were impaired during the three and nine months ended September 30, 2015 and 2014, reflecting recurring amortization of undeveloped leasehold costs on properties the Company expects will not be transferred to proved properties over the lives of the leases based on drilling plans, 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 comprehensive income (loss).

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2015	2014	2015	2014
Proved property impairments	$36,302	$38,046	$111,346	$69,337
Unproved property impairments	60,395	47,515	209,784	153,748
Total	$96,697	$85,561	$321,130	$223,085

Financial Instruments Not Recorded at Fair Value

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

	September 30, 2015		December 31, 2014	
In thousands	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Credit facility	$1,345,000	$1,345,000	$165,000	$165,000
Note payable	14,832	13,300	16,375	14,900
7.375% Senior Notes due 2020	196,424	204,100	195,997	213,000
7.125% Senior Notes due 2021	395,184	412,000	394,668	421,000
5% Senior Notes due 2022	1,996,747	1,760,100	1,996,507	1,857,900
4.5% Senior Notes due 2023	1,481,945	1,290,000	1,480,479	1,372,800
3.8% Senior Notes due 2024	989,681	820,400	988,940	868,700
4.9% Senior Notes due 2044	691,016	504,800	690,912	572,400
Total debt	$7,110,829	$6,349,700	$5,928,878	$5,485,700

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 7.375% Senior Notes due 2020 (“2020 Notes”), the 7.125% Senior Notes due 2021 (“2021 Notes”), the 5% Senior Notes due 2022 (“2022 Notes”), the 4.5% Senior Notes due 2023 ("2023 Notes"), the 3.8% Senior Notes due 2024 ("2024 Notes"), and the 4.9% Senior Notes due 2044 ("2044 Notes") are based on quoted market prices and, accordingly, are classified as Level 1 in the fair value hierarchy.

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

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Note 6. Long-Term Debt

Long-term debt, net of unamortized discounts, premiums, and debt issuance costs totaling $49.1 million and $52.6 million at September 30, 2015 and December 31, 2014, respectively, consists of the following. See Note 2. Basis of Presentation and Significant Accounting Policies—Adoption of new accounting pronouncement for a discussion of the impact on long-term debt from the Company's adoption of ASU 2015-03.

In thousands	September 30, 2015	December 31, 2014
Credit facility	$1,345,000	$165,000
Note payable	14,832	16,375
7.375% Senior Notes due 2020	196,424	195,997
7.125% Senior Notes due 2021	395,184	394,668
5% Senior Notes due 2022	1,996,747	1,996,507
4.5% Senior Notes due 2023	1,481,945	1,480,479
3.8% Senior Notes due 2024	989,681	988,940
4.9% Senior Notes due 2044	691,016	690,912
Total debt	$7,110,829	$5,928,878
Less: Current portion of long-term debt	2,127	2,078
Long-term debt, net of current portion	$7,108,702	$5,926,800

Credit Facility

The Company has an unsecured credit facility, maturing on May 16, 2019, with aggregate commitments totaling $2.5 billion as of September 30, 2015, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders.

The Company had $1.35 billion and $165 million of outstanding borrowings on its credit facility at September 30, 2015 and December 31, 2014, respectively. Borrowings 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 weighted-average interest rate on outstanding borrowings at September 30, 2015 was 1.7%.

The Company had approximately $1.15 billion of borrowing availability on its credit facility at September 30, 2015 and incurs commitment fees based on currently assigned credit ratings of 0.225% per annum on the daily average amount of unused borrowing availability.

The credit facility contains certain restrictive covenants including a requirement that the Company maintain a consolidated net debt to total 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 plus, to the extent resulting in a reduction of total shareholders’ equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014. The Company was in compliance with this covenant at September 30, 2015.

See Note 11. Subsequent Events for a discussion of changes to the Company's credit facility and other borrowings subsequent to September 30, 2015.

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Senior Notes
The following table summarizes the face values, maturity dates, semi-annual interest payment dates, and optional redemption periods related to the Company's outstanding senior note obligations at September 30, 2015.

	2020 Notes	2021 Notes	2022 Notes	2023 Notes	2024 Notes	2044 Notes
Face value (in thousands)	$200,000	$400,000	$2,000,000	$1,500,000	$1,000,000	$700,000
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, Sep 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

(1) On or after these dates, the Company has the option to redeem all or a portion of its senior notes of the applicable series 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 of the applicable series at the "make-whole" redemption prices or amounts specified in the Indentures 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 other things, limit the Company's ability to create liens securing certain indebtedness, enter into certain sale and leaseback transactions, and consolidate, merge or transfer certain assets. The senior note covenants are subject to a number of important exceptions and qualifications. The Company was in compliance with these covenants at September 30, 2015. Two of the Company's subsidiaries, Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, which have no material assets or operations, fully and unconditionally guarantee the senior notes. The Company's other subsidiaries, the value of whose assets and operations are minor, do not guarantee the senior notes.

Note Payable
In February 2012, 20 Broadway Associates LLC, a 100% owned subsidiary of the Company, borrowed $22 million under a 10-year amortizing term loan secured by the Company's corporate office building in Oklahoma City, Oklahoma. The loan bears interest at a fixed rate of 3.14% per annum. Principal and interest are payable monthly through the loan's maturity date of February 26, 2022. Accordingly, approximately $2.1 million is reflected as a current liability under the caption "Current portion of long-term debt" in the condensed consolidated balance sheets as of September 30, 2015.

2014 Redemption of Senior Notes
In July 2014, the Company redeemed its then outstanding 8.25% Senior Notes due 2019 ("2019 Notes") using a portion of the proceeds from the May 2014 issuances of 2024 Notes and 2044 Notes. The 2019 Notes were redeemed for $317.5 million, representing a make-whole amount calculated in accordance with the terms of the 2019 Notes and related indenture. The Company recognized a pre-tax loss of $24.5 million related to the redemption, which included the make-whole premium and the write-off of deferred financing costs and unaccreted debt discount and is reflected under the caption "Loss on extinguishment of debt" in the unaudited condensed consolidated statements of comprehensive income (loss) for the three and nine months ended September 30, 2014.

Note 7. Commitments and Contingencies
Included below is a discussion of various future commitments of the Company as of September 30, 2015. The commitments under these arrangements are not recorded in the accompanying condensed consolidated balance sheets.

Drilling commitments – As of September 30, 2015, the Company had drilling rig contracts with various terms extending through March 2019. 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 strategic plays. Future commitments as of September 30, 2015 total

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approximately $475 million, of which $59 million is expected to be incurred in the remainder of 2015, $220 million in 2016, $129 million in 2017, $62 million in 2018, and $5 million in 2019.

Pipeline transportation commitments – The Company has entered into firm transportation commitments to guarantee pipeline access capacity on operational crude oil and natural gas pipelines. The commitments, which have varying terms extending as far as 2027, require the Company to pay per-unit transportation charges regardless of the amount of pipeline capacity used. Future commitments remaining as of September 30, 2015 under the operational pipeline transportation arrangements amount to approximately $1.1 billion, of which $52 million is expected to be incurred in the remainder of 2015, $213 million in 2016, $210 million in 2017, $206 million in 2018, $170 million in 2019, and $217 million thereafter.

Further, the Company was a party to a five year firm transportation commitment (the "Agreement") for a future crude oil pipeline project being considered for development that is not yet operational. The project requires the granting of regulatory approvals and requires additional construction efforts by the counterparty before being completed. The project has faced significant delays and has failed to gain the necessary permits and approvals. As a result of the persistent delays and continuous uncertainty, the Agreement's basic assumptions and purpose have become commercially impracticable. Accordingly, in 2015 the Company provided a shipper termination notice pursuant to the Agreement and formally provided the counterparty with the Company's termination of the Agreement in its entirety. The Company's previously disclosed commitments under the Agreement totaled approximately $260 million, which is no longer expected to be incurred.

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.

Fuel purchase commitment – The Company has entered into a forward purchase contract with a third party to purchase specified quantities of diesel fuel at specified prices each month through June 2016 for use in the normal course of drilling operations. Over the remaining contract term, the Company has committed to purchase approximately 16 million gallons of diesel fuel at varying prices depending on the grade of diesel fuel purchased and the timing and location of delivery. The contract satisfies a significant portion of the Company's anticipated diesel fuel needs and provides for physical delivery to desired locations. Future commitments under the arrangement as of September 30, 2015 total approximately $47 million, of which $16 million is expected to be incurred in the remainder of 2015 and $31 million is expected to be incurred in 2016.

Litigation – In November 2010, a putative class action was filed in the District Court of Blaine County, Oklahoma by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. The Petition alleged the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs 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 proposed class. On November 3, 2014, plaintiffs filed an Amended Petition that did not add any substantive claims, but sought a "hybrid class action" in which they sought certification of certain claims for injunctive relief, reserving the right to seek a further class certification on money damages in the future. Plaintiffs filed an Amended Motion for Class Certification on January 9, 2015, that modified the proposed class to royalty owners in Oklahoma production from July 1, 1993, to the present (instead of 1980 to the present) and sought certification of over 45 separate "issues" for injunctive or declaratory relief, again, reserving the right to seek a further class certification of money damages in the future. The Company responded to the petition, its amendment, and the motions for class certification denying the allegations and raising a number of affirmative defenses and legal arguments to each of the claims and filings. Certain discovery was undertaken and the "hybrid" motion was briefed by plaintiffs and the Company. A hearing on the "hybrid" class certification was held on June 1st and 2nd, 2015. On June 11, 2015, the trial court certified a "hybrid" class as requested by plaintiffs. The Company has appealed the trial court's class certification order, which will be reviewed de novo by the appellate court. A mediation is scheduled for December 7, 2015. 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. Although not currently at issue in the "hybrid" certification, plaintiffs have alleged underpayments in excess of $200 million that they may claim as damages, 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 will continue to assert its defenses to the case as certified as well as any future attempt to certify a money damages class.

The Company is involved in various other legal proceedings including, but not limited to, commercial disputes, claims from royalty and surface owners, property damage claims, personal injury claims and other matters. While the outcome of these legal matters cannot be predicted with certainty, the Company does not expect them to have a material effect on its financial condition, results of operations or cash flows. As of September 30, 2015 and December 31, 2014, the Company had recorded a liability in the condensed consolidated balance sheets under the caption “Other noncurrent liabilities” of $6.1 million and $2.9 million, respectively, for various matters, none of which are believed to be individually significant.

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

Note 8. Stock-Based Compensation

The Company has granted restricted stock to employees and directors pursuant to the Continental Resources, Inc. 2005 Long-Term Incentive Plan (“2005 Plan”) 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 comprehensive income (loss), was $12.9 million and $13.4 million for the three months ended September 30, 2015 and 2014, respectively, and $40.3 million and $39.4 million for the nine months ended September 30, 2015 and 2014, respectively.

In May 2013, the Company adopted the 2013 Plan and reserved a maximum of 19,680,072 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 September 30, 2015, the Company had a maximum of 17,027,803 shares of restricted stock available to grant to officers, directors and employees under the 2013 Plan.

Restricted stock is awarded in the name of the recipient and constitutes issued and outstanding shares of the Company’s common stock for all corporate purposes during the period of restriction and, except as otherwise provided under the 2013 Plan or agreement relevant to a given award, includes the right to vote the restricted stock or to receive dividends, subject to forfeiture. Restricted stock grants generally vest over periods ranging from one to three years.

A summary of changes in non-vested restricted shares outstanding for the nine months ended September 30, 2015 is presented below:

	Number of non-vested shares	Weighted average grant-date fair value
Non-vested restricted shares outstanding at December 31, 2014	2,678,764	$49.40
Granted	1,383,557	47.36
Vested	(420,852)	45.92
Forfeited	(291,999)	50.99
Non-vested restricted shares outstanding at September 30, 2015	3,349,470	$48.86

The grant date fair value of restricted stock represents the closing market price of the Company’s common stock on the date of grant. Compensation expense for a restricted stock grant is a fixed amount determined at the grant date fair value and is recognized ratably over the vesting period as services are rendered by employees and directors. The expected life of restricted stock is based on the non-vested period that remains subsequent to the date of grant. There are no post-vesting restrictions related to the Company’s restricted stock. The fair value of restricted stock that vested during the nine months ended September 30, 2015 at the vesting date was approximately $19.1 million. As of September 30, 2015, there was approximately $81 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 1.4 years.

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

Note 9. Accumulated Other Comprehensive Loss
Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in "Accumulated other comprehensive loss" within shareholders' equity on the condensed consolidated balance sheets. The following table summarizes the change in accumulated other comprehensive loss for the three and nine months ended September 30, 2015:

In thousands	Three months ended September 30, 2015	Nine months ended September 30, 2015
Beginning accumulated other comprehensive loss, net of tax	$(2,865)	$(385)
Foreign currency translation adjustments	(438)	(2,918)
Income tax benefit (1)	—	—
Other comprehensive loss, net of tax	(438)	(2,918)
Ending accumulated other comprehensive loss, net of tax	$(3,303)	$(3,303)

(1) A valuation allowance has been recognized against deferred tax assets associated with losses generated by the Company's Canadian operations, thereby resulting in no income taxes on other comprehensive loss for the period.

Note 10. Property Dispositions
During the nine months ended September 30, 2015, the Company sold certain non-strategic properties in various areas to third parties for proceeds totaling $33.2 million. The proceeds primarily related to the assignment of certain non-producing leasehold acreage in Oklahoma to a third party for $25.9 million in May 2015. The Company recognized a pre-tax gain on the transaction of $20.5 million. The assigned properties represented an immaterial portion of the Company's leasehold acreage.
During the nine months ended September 30, 2014, the Company sold certain non-strategic properties in various areas to third parties for proceeds totaling $129.3 million. The proceeds primarily related to dispositions of properties in the Niobrara play in Colorado and Wyoming in March 2014 for proceeds totaling $30.3 million and $85.8 million of proceeds received in conjunction with the disposition of a portion of the Company's Northwest Cana properties in Oklahoma in September 2014. The disposed properties represented an immaterial portion of the Company's total proved reserves, production, and revenues.

Note 11. Subsequent Events
New term loan
On November 4, 2015, the Company, as borrower, and its subsidiaries Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, as guarantors, entered into a Term Loan Agreement with MUFG Union Bank, N.A., as Administrative Agent, Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A. and Mizuho Bank, LTD., as Co-Syndication Agents, and Compass Bank, Toronto Dominion (Texas) LLC and U.S. Bank National Association, as Co-Documentation Agents, and the other lenders party thereto (the "Term Loan"). The Term Loan provides for aggregate lender commitments of $500 million, the full amount of which the Company borrowed at the closing of the Term Loan. The proceeds from the Term Loan were used to repay a portion of the borrowings outstanding on the Company's credit facility, which had a balance prior to repayment of $1.38 billion.
The Term Loan will mature on November 4, 2018 and will bear interest at a market-based interest rate plus a margin that is based on the terms of the borrowing and the credit ratings assigned to the Company's senior, unsecured, long-term indebtedness. The initial per annum interest rate on the Term Loan is LIBOR plus 1.375%, which is 0.125% lower than the interest rate currently available under the Company's credit facility for similar borrowings.
The terms of the Term Loan include covenants limiting the amount of debt that can be incurred by the Company's subsidiaries that do not guarantee the Term Loan and that restrict the ability of the Company and its Restricted Subsidiaries (as such term is defined in the Term Loan) to incur liens and engage in sale and leaseback transactions. The Term Loan also contains a financial covenant that requires the Company to maintain a debt to capitalization ratio that does not exceed 0.65 to 1.0 and a covenant that restricts the ability of the Company to merge, consolidate or sell all or substantially all of its assets.

The Term Loan includes events of default relating to customary matters, including, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross default and cross acceleration with respect to certain non-payments in connection with indebtedness in an aggregate principal amount of $100 million or more; bankruptcy; judgments involving liability of $100 million or more that are not paid; and ERISA events. Many events of default are subject to customary notice and cure periods.

MUFG Union Bank, N.A. was the arranger and book runner for the Term Loan. In addition, certain of the lenders party to the Term Loan, and their respective affiliates, have performed, and may in the future perform, various commercial banking, investment banking and other financial advisory services for the Company and its subsidiaries for which they have received, and will receive, customary fees and expenses.

The above description of the material terms and conditions of the Term Loan does not purport to be complete and is qualified in its entirety by reference to the full text of the Term Loan, which is filed as Exhibit 10.1 to this Form 10-Q.

Increase in credit facility commitments

On November 4, 2015, the aggregate lender commitments on the Company's credit facility were increased from $2.5 billion to $2.75 billion to provide enhanced liquidity for the Company. After giving effect to the increased commitments and the use of proceeds from the $500 million Term Loan discussed above to repay borrowings outstanding under the Company's credit facility, the Company had approximately $880 million of outstanding borrowings and $1.87 billion of availability on its credit facility at November 4, 2015.

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, 2014. 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, 2014, 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 company engaged in the exploration, development and production of crude oil and natural gas. We derive the majority of our operating income and cash flows from the sale of crude oil and natural gas and expect this to continue in the future. Our operations are primarily focused on exploration and development activities in the Bakken field of North Dakota and Montana and the SCOOP play in Oklahoma.

Business Environment and Outlook

Commodity prices have remained depressed through September 30, 2015 and continue to be volatile and unpredictable. We remain focused on balancing our capital expenditures with operating cash flows and have taken measures to achieve this balance at a $50 WTI oil price. We have reduced our operated rig count and are deferring well completion activities except for where we have contractual considerations or where completing wells accomplishes specific strategic objectives. These measures will continue to slow our rate of capital spending and production growth for the remainder of 2015 and are expected to result in a decline in production in the 2015 fourth quarter compared to the 2015 third quarter.

2015 Highlights

Production

Production for the third quarter of 2015 averaged 228,278 Boe per day, an increase of 1% from the second quarter of 2015 and 25% higher than the third quarter of 2014. Year to date production averaged 220,630 Boe per day, a 32% increase over the comparable 2014 period.

North Dakota Bakken production averaged 123,560 Boe per day for the third quarter of 2015, a 3% decrease from the second quarter of 2015 and 16% higher than the third quarter of 2014. Year to date, North Dakota Bakken production averaged 124,139 Boe per day, a 31% increase over the comparable 2014 period.

SCOOP production averaged 69,136 Boe per day for the third quarter of 2015, an 11% increase over the second quarter of 2015 and 90% higher than the third quarter of 2014. Year to date, SCOOP production averaged 60,592 Boe per day, an 82% increase over the comparable 2014 period.

SCOOP comprised 30% of our total production for the 2015 third quarter compared to 28% for the 2015 second quarter and 20% for the 2014 third quarter. SCOOP comprised 27% of our total production for year to date 2015 compared to 20% for the comparable 2014 period.

Revenues

Crude oil and natural gas revenues for the 2015 third quarter decreased 46% compared to the 2014 third quarter driven by a 57% decrease in realized commodity prices, the effect of which was partially offset by a 25% increase in total sales volumes.

Year to date crude oil and natural gas revenues decreased 39% from the comparable 2014 period driven by a 54% decrease in realized commodity prices, the effect of which was partially offset by a 33% increase in total sales volumes.

Average crude oil sales prices for the third quarter and year to date periods of 2015 decreased 54% and 52%, respectively, from the comparable 2014 periods.

Crude oil sales volumes for the third quarter and year to date periods of 2015 increased 15% and 27%, respectively, from the comparable 2014 periods.

Average natural gas sales prices for the third quarter and year to date periods of 2015 decreased 56% and 59%, respectively, from the comparable 2014 periods.

Natural gas sales volumes for the third quarter and year to date periods of 2015 increased 48% and 45%, respectively, from the comparable 2014 periods.

Proved property impairments

Decreases in commodity prices in the third quarter of 2015 adversely impacted the recoverability of capitalized costs in certain operating areas and contributed to the recognition of non-cash impairment charges for proved properties totaling $36.3 million for the third quarter, bringing year to date proved property impairments to $111.3 million through September 30, 2015. These impairments were primarily concentrated in non-core areas of our North and South regions.

Capital expenditures and drilling activity

We invested approximately $540.0 million in our capital program in the third quarter of 2015 compared to $585.5 million for the 2015 second quarter and $983.8 million for the 2015 first quarter. Year to date non-acquisition capital expenditures totaled $2.1 billion through September 30, 2015.

For the quarter and year to date periods of 2015 we participated in the drilling and completion of the following number of wells by area:

	1Q 2015		2Q 2015		3Q 2015		YTD 2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
North Dakota Bakken	210	62	160	55	160	35	530	152
Montana Bakken	8	6	1	—	—	—	9	6
SCOOP	74	37	55	18	34	11	163	66
Northwest Cana	—	—	5	2	6	2	11	4
STACK	—	—	—	—	3	1	3	1
Other	12	6	5	—	1	—	18	6
Total wells	304	111	226	75	204	49	734	235

Included in the completed well counts at September 30, 2015 are 14 gross (9 net) wells that were completed during the third quarter but are not yet producing. Additionally, as of September 30, 2015 we had 105 gross (80 net) operated wells that are drilled but not yet completed. Due to current market conditions we have chosen to defer completions and new production on certain wells until the commodity pricing environment improves.

As of September 30, 2015, we operated 23 rigs on our properties, down from 27 operated rigs at June 30, 2015 and 49 operated rigs at December 31, 2014.

Credit facility and liquidity

At September 30, 2015, we had $17.0 million of cash and cash equivalents and $1.15 billion of borrowing availability on our credit facility after considering outstanding borrowings and letters of credit. We had $1.35 billion of outstanding borrowings on our credit facility at September 30, 2015 compared to $1.23 billion at June 30, 2015 and $165 million at December 31, 2014.

Credit facility borrowings, net of repayments, totaled $120 million for the 2015 third quarter compared to $270 million for the 2015 second quarter and $790 million for the 2015 first quarter, the decreasing trend of which resulted from a reduced level of capital expenditures due to our efforts to align capital expenditures with operating cash flows in response to decreased commodity prices.

On November 4, 2015, aggregate lender commitments on our credit facility were increased from $2.5 billion to $2.75 billion to provide enhanced liquidity. Additionally on that date, we entered into a $500 million term loan maturing in November 2018 and used the proceeds therefrom to repay a portion of our outstanding credit facility borrowings. After giving effect to the repayment and increased commitments, we had approximately $880 million of outstanding borrowings and $1.87 billion of availability on our credit facility at November 4, 2015.

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 September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Average daily production:				
Crude oil (Bbl per day)	147,472	127,788	146,975	116,954
Natural gas (Mcf per day)	484,834	327,287	441,930	304,453
Crude oil equivalents (Boe per day)	228,278	182,335	220,630	167,696
Average sales prices:				
Crude oil ($/Bbl)	$38.95	$85.49	$42.60	$89.02
Natural gas ($/Mcf)	$2.23	$5.10	$2.39	$5.80
Crude oil equivalents ($/Boe)	$29.90	$69.08	$33.18	$72.52
Crude oil sales price differential to NYMEX ($/Bbl)	$(7.54)	$(11.77)	$(8.54)	$(10.60)
Natural gas sales price premium (discount) to NYMEX ($/Mcf)	$(0.54)	$1.04	$(0.39)	$1.28
Production expenses ($/Boe)	$4.00	$5.80	$4.45	$5.69
Production taxes (% of oil and gas revenues)	7.6%	8.3%	7.8%	8.1%
DD&A ($/Boe)	$21.36	$21.65	$21.36	$21.17
General and administrative expenses ($/Boe) (1)	$1.95	$1.82	$1.71	$2.08
Non-cash equity compensation ($/Boe)	$0.61	$0.80	$0.67	$0.87
Net income (loss) (in thousands)	$(82,423)	$533,521	$(213,992)	$863,293
Diluted net income (loss) per share	$(0.22)	$1.44	$(0.58)	$2.33
EBITDAX (in thousands) (2)	$472,221	$947,635	$1,558,656	$2,590,980

(1) Excludes non-cash equity compensation expense.

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

Three months ended September 30, 2015 compared to the three months ended September 30, 2014

Results of Operations

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

	Three months ended September 30,	
In thousands, except sales price data	2015	2014
Crude oil and natural gas sales	$628,457	$1,160,281
Gain on derivative instruments, net	46,527	473,999
Crude oil and natural gas service operations	7,685	11,048
Total revenues	682,669	1,645,328
Operating costs and expenses	(735,025)	(700,431)
Other expenses, net (1)	(78,811)	(98,036)
Income (loss) before income taxes	(131,167)	846,861
(Provision) benefit for income taxes	48,744	(313,340)
Net income (loss)	$(82,423)	$533,521
Production volumes:		
Crude oil (MBbl)	13,567	11,756
Natural gas (MMcf)	44,605	30,110
Crude oil equivalents (MBoe)	21,002	16,775
Sales volumes:		
Crude oil (MBbl)	13,582	11,777
Natural gas (MMcf)	44,605	30,110
Crude oil equivalents (MBoe)	21,016	16,796
Average sales prices:		
Crude oil ($/Bbl)	$38.95	$85.49
Natural gas ($/Mcf)	2.23	5.10
Crude oil equivalents ($/Boe)	29.90	69.08

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

Production

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

	Three months ended September 30,				Volume increase	Volume percent increase
	2015		2014			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	13,567	65 %	11,756	70 %	1,811	15 %
Natural gas (MMcf)	44,605	35 %	30,110	30 %	14,495	48 %
Total (MBoe)	21,002	100 %	16,775	100 %	4,227	25 %

	Three months ended September 30,				Volume increase	Volume percent increase
	2015		2014			
	MBoe	Percent	MBoe	Percent		
North Region	13,681	65 %	12,519	75 %	1,162	9 %
South Region	7,321	35 %	4,256	25 %	3,065	72 %
Total	21,002	100 %	16,775	100 %	4,227	25 %

The 15% increase in crude oil production for the third quarter was driven by increased production from our properties in the North Dakota Bakken field and SCOOP play. Production in North Dakota Bakken increased 1,160 MBbls, or 14%, over the prior year third quarter, while SCOOP production increased 1,096 MBbls, or 116%. Production growth in these areas was primarily due to additional drilling and completion activity resulting from our drilling program. These increases were partially offset by a decrease in production from our properties in Montana Bakken and the Red River units totaling 456 MBbls, or 19%, compared to the prior year third quarter due to a combination of natural declines in production and reduced drilling activity.

The 48% increase in natural gas production for the third quarter was driven by increased production from our properties in the SCOOP play, Bakken field, and Northwest Cana field due to additional wells being completed and producing subsequent to September 30, 2014. Natural gas production in SCOOP increased 11,522 MMcf, or 80%, over the prior year third quarter, while Bakken production increased 2,593 MMcf, or 25%, and Northwest Cana production increased 697 MMcf, or 28%. These increases were partially offset by decreases in production from various areas in our North and South regions primarily due to natural declines in production.
Our ongoing reduction in capital spending prompted by depressed commodity prices has adversely impacted our production growth. Our average daily production for the month of September 2015 was approximately 222,000 Boe per day, a decrease of 3% compared to our production of approximately 230,000 Boe per day for the month of June 2015. We expect our year-over-year production growth to continue slowing for the remainder of 2015 as we continue to curtail our capital spending, and we expect to exit the year with daily production of approximately 210,000 Boe per day.
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 third quarter of 2015 were $628.5 million, a 46% decrease from sales of $1.16 billion for the same period in 2014 primarily due to a significant decrease in commodity prices, partially offset by an increase in sales volumes.
Our crude oil sales prices averaged $38.95 per barrel in the 2015 third quarter compared to $85.49 for the 2014 third quarter. Market prices for crude oil remained depressed in the 2015 third quarter, resulting in significantly lower realized sales prices compared to the prior year. The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel was $7.54 for the 2015 third quarter compared to $11.77 for the 2014 third quarter. The improved differential was due in part to increased availability and use of pipeline transportation to move our crude oil to market with less dependence on more costly rail transportation.
Our average natural gas sales price for the 2015 third quarter decreased to $2.23 per Mcf compared to $5.10 for the 2014 third quarter due to lower market prices for natural gas and natural gas liquids ("NGLs"). Our natural gas production is primarily sold at the wellhead with price realizations being impacted by the volume and value of NGLs that purchasers extract from our sales stream. The difference between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices was a discount of $0.54 per Mcf for the 2015 third quarter compared to a premium of $1.04 for the 2014 third quarter. NGL prices remained depressed in the 2015 third quarter in conjunction with low crude oil prices, which reduced the value of our natural gas sales stream and unfavorably impacted the difference between our realized prices and Henry Hub benchmark pricing.
Crude oil, natural gas and NGL prices remain volatile and we are unable to predict the impact future price changes may have on our revenues and differentials for the remainder of 2015 and beyond.
Our sales volumes for the third quarter of 2015 increased 4,220 MBoe, or 25%, over the comparable period in 2014 primarily due to an increase in producing wells resulting from the success of our drilling programs in North Dakota Bakken and SCOOP. 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 and caused crude oil sales volumes to be higher than crude oil production by 15 MBbls for the third quarter of 2015.
Derivatives. Changes in commodity prices during the third quarter of 2015 had a favorable impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $46.5 million for the period. Our revenues may 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 commodity prices.

The following table presents cash settlements on matured derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented.

	Three months ended September 30,	
In thousands	2015	2014
Cash received (paid) on derivatives:		
Crude oil derivatives	$—	$(4,359)
Natural gas derivatives	11,917	4,549
Cash received on derivatives, net	11,917	190
Non-cash gain on derivatives:		
Crude oil derivatives	617	444,023
Natural gas derivatives	33,993	29,786
Non-cash gain on derivatives, net	34,610	473,809
Gain on derivative instruments, net	$46,527	$473,999

Operating Costs and Expenses

Production Expenses. Production expenses decreased 14% from $97.4 million for the third quarter of 2014 to $84.0 million for the third quarter of 2015. Costs on a per-Boe basis decreased to $4.00 for the 2015 third quarter compared to $5.80 for the 2014 third quarter. These decreases primarily resulted from the effects of curtailed spending and reduced service costs being realized in conjunction with depressed commodity prices, along with a higher portion of our production coming from natural gas wells in the SCOOP area which typically have lower operating costs compared to other areas.

Production Taxes and Other Expenses. Production taxes and other expenses decreased $49.7 million, or 51%, to $47.7 million for the third quarter of 2015 compared to $97.4 million for the third quarter of 2014 primarily due to lower crude oil and natural gas revenues resulting from the significant decrease in commodity prices over the prior year period. Production taxes as a percentage of crude oil and natural gas revenues were 7.6% for the third quarter of 2015 compared to 8.3% for the third quarter of 2014, the decrease of which resulted from 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.

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 wells are taxed at a lower rate during their initial months of production, with the tax rate subsequently increasing after a specified period of time or when specified production volumes are achieved. Through June 30, 2015, revenues from new wells in Oklahoma were taxed at 1% for the first 48 months of production, after which the tax rate increases to 7%. Effective July 1, 2015, the tax rate on new Oklahoma wells spud after that date was changed to 2% for the first 36 months of production and 7% thereafter.

At September 30, 2015, North Dakota had a crude oil tax structure based on a 5% production tax and a 6.5% oil extraction tax for a combined tax of 11.5% of crude oil revenues. In April 2015, new legislation was signed into law in North Dakota that eliminated the then-existing price-based oil extraction tax incentives and set a lower oil extraction tax rate. The new law reduces the oil extraction tax from 6.5% to 5% effective January 1, 2016, resulting in a total tax of 10% on crude oil revenues when combined with the 5% production tax which was not changed by the new law. Under the new law, the oil extraction tax will increase from 5% to 6%, for a total tax rate of 11%, if the average WTI oil price is above $90 per barrel (indexed for inflation) for three consecutive months. The oil extraction tax will revert back to 5% if the average WTI oil price falls below $90 per barrel for three consecutive months.

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

	Three months ended September 30,	
In thousands	2015	2014

Geological and geophysical costs	$52	$8,755
Exploratory dry hole costs	180	4,759
Exploration expenses	$232	$13,514

The decrease in geological and geophysical expenses in the third quarter of 2015 was attributed to changes in the timing and amount of costs incurred by the Company and recouped from joint interest partners between periods.
Depreciation, Depletion, Amortization and Accretion (“DD&A”). Total DD&A increased $85.1 million, or 23%, to $448.8 million for the third quarter of 2015 compared to $363.7 million for the third quarter of 2014 primarily due to a 25% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis for the periods presented.

	Three months ended September 30,	
$/Boe	2015	2014
Crude oil and natural gas	$20.98	$21.26
Other equipment	0.32	0.34
Asset retirement obligation accretion	0.06	0.05
Depreciation, depletion, amortization and accretion	$21.36	$21.65

Estimated proved reserves are a key component in our computation of DD&A expense. Holding all other factors constant, if proved reserves are revised downward, the rate at which we record DD&A expense would increase. If commodity prices remain at current levels or decline further, downward revisions of proved reserves may occur in the future, which may be significant and would result in an increase in our DD&A rate. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on our future DD&A rate.
Property Impairments. Total property impairments increased $11.1 million, or 13%, to $96.7 million for the third quarter of 2015 compared to $85.6 million for the 2014 third quarter.
Impairments of proved properties totaled $36.3 million for the third quarter of 2015 compared to $38.0 million for the third quarter of 2014. The 2015 third quarter impairments reflect fair value adjustments prompted by a continued decrease in commodity prices and were primarily concentrated in the Buffalo Red River units ($26.3 million) and the Medicine Pole Hills units ($8.2 million).
Estimated reserves are a key component in assessing proved properties for impairment. If commodity prices remain at current levels or decline further, downward revisions of reserves may be significant in the future and could result in additional impairments of proved properties in the remainder of 2015. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on future impairments, if any.
Impairments of non-producing properties increased $12.9 million for the third quarter of 2015 to $60.4 million compared to $47.5 million for the third quarter of 2014. The increase was primarily the result of higher rates of amortization being applied to undeveloped leasehold costs resulting from changes in the Company's estimates of undeveloped properties not expected to be developed before lease expiration, particularly in response to decreased commodity prices which have altered our drilling plans. Our rates of amortization may continue to increase in future periods if commodity prices remain at current levels or decline further and additional changes are made to drilling plans.
General and Administrative ("G&A") Expenses. G&A expenses increased $9.8 million, or 22%, to $53.8 million for the third quarter of 2015 from $44.0 million for the 2014 third quarter primarily due to an increase in personnel costs associated with our growth. G&A expenses include non-cash charges for equity compensation of $12.9 million and $13.4 million for the third quarters of 2015 and 2014, respectively.
The following table shows the components of G&A expenses on a unit of sales basis for the periods presented.

	Three months ended September 30,	
$/Boe	2015	2014
General and administrative expenses	$1.95	$1.82
Non-cash equity compensation	0.61	0.80
Total general and administrative expenses	$2.56	$2.62

The decrease in equity compensation expense on a per-Boe basis in 2015 was due to an increase in the estimated rate of forfeitures of unvested restricted stock based on historical experience, which resulted in lower recognition of expense in 2015, coupled with the increase in sales volumes from new well completions with no comparable increase in equity compensation expense.

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Interest Expense. Interest expense increased $5.5 million, or 7%, to $79.4 million for the third quarter of 2015 compared to $73.9 million for the third quarter of 2014 due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for the 2015 third quarter was approximately $7.1 billion with a weighted average interest rate of 4.3% compared to averages of $5.9 billion and 4.8% for the 2014 third quarter. The increase in outstanding debt resulted from borrowings incurred subsequent to September 30, 2014 to fund our 2014 and 2015 capital programs.

Income Taxes. We recorded an income tax benefit for the third quarter of 2015 of $48.7 million compared to income tax expense of $313.3 million for the third quarter of 2014, resulting in effective tax rates of approximately 37% for both periods after taking into account permanent taxable differences and valuation allowances. For the 2015 third quarter, we provided for income taxes at a combined federal and state tax rate of 38% of pre-tax losses generated by our operations in the United States. Our 2015 third quarter effective tax rate was impacted by a $0.9 million valuation allowance recognized against deferred tax assets associated with operating loss carryforwards generated by our Canadian subsidiary during the quarter for which we do not believe we will realize a benefit.

Nine months ended September 30, 2015 compared to the nine months ended September 30, 2014

Results of Operations

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

	Nine months ended September 30,			
In thousands, except sales price data	2015		2014	
Crude oil and natural gas sales	$2,001,151		$3,300,699	
Gain on derivative instruments, net	74,545		171,801	
Crude oil and natural gas service operations	28,991		31,418	
Total revenues	2,104,687		3,503,918	
Operating costs and expenses	(2,185,872	)	(1,901,310	)
Other expenses, net (1)	(231,430	)	(232,300	)
Income (loss) before income taxes	(312,615	)	1,370,308	
(Provision) benefit for income taxes	98,623		(507,015	)
Net income (loss)	$(213,992	)	$863,293	
Production volumes:				
Crude oil (MBbl)	40,124		31,928	
Natural gas (MMcf)	120,647		83,116	
Crude oil equivalents (MBoe)	60,232		45,781	
Sales volumes:				
Crude oil (MBbl)	40,210		31,664	
Natural gas (MMcf)	120,647		83,116	
Crude oil equivalents (MBoe)	60,318		45,516	
Average sales prices:				
Crude oil ($/Bbl)	$42.60		$89.02	
Natural gas ($/Mcf)	2.39		5.80	
Crude oil equivalents ($/Boe)	33.18		72.52	

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

Production

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

	Nine months ended September 30,				Volume increase	Volume percent increase
	2015		2014			
	Volume	Percent	Volume	Percent		
Crude oil (MBbl)	40,124	67 %	31,928	70 %	8,196	26 %
Natural gas (MMcf)	120,647	33 %	83,116	30 %	37,531	45 %
Total (MBoe)	60,232	100 %	45,781	100 %	14,451	32 %

	Nine months ended September 30,				Volume increase	Volume percent increase
	2015		2014			
	MBoe	Percent	MBoe	Percent		
North Region	41,257	68 %	33,890	74 %	7,367	22 %
South Region	18,975	32 %	11,891	26 %	7,084	60 %
Total	60,232	100 %	45,781	100 %	14,451	32 %

The 26% increase in crude oil production for year to date 2015 was driven by increased production from our properties in the North Dakota Bakken field and SCOOP play. Production in North Dakota Bakken increased 6,019 MBbls, or 27%, over the prior year, while SCOOP production increased 2,843 MBbls, or 116%. Production growth in these areas was primarily due to additional drilling and completion activity resulting from our drilling program. These increases were partially offset by a decrease in production from our properties in Montana Bakken and the Red River units totaling 714 MBbls, or 10%, compared to the prior year due to a combination of natural declines in production and reduced drilling activity.

The 45% increase in natural gas production for year to date 2015 was driven by increased production from our properties in the Bakken field and SCOOP play due to additional wells being completed and producing subsequent to September 30, 2014. Natural gas production in the Bakken field increased 11,842 MMcf, or 45%, over the prior year, while SCOOP production increased 27,565 MMcf, or 69%. These increases were partially offset by decreases in production from various areas in our North and South regions primarily due to natural declines in production.

Our ongoing reduction in capital spending prompted by depressed commodity prices has adversely impacted our production growth and we do not expect our 32% year-over-year growth in total production through September 30, 2015 to be sustained for the remainder of 2015. We expect to exit 2015 with average daily production of approximately 210,000 Boe per day.

Revenues

Crude Oil and Natural Gas Sales. Crude oil and natural gas sales for year to date 2015 were $2.00 billion, a 39% decrease from sales of $3.30 billion for the same period in 2014 primarily due to a significant decrease in commodity prices, partially offset by an increase in sales volumes.

Our crude oil sales prices averaged $42.60 per barrel for year to date 2015 compared to $89.02 for year to date 2014. Market prices for crude oil have remained depressed throughout 2015, resulting in significantly lower realized sales prices compared to the prior year. The differential between NYMEX WTI calendar month average crude oil prices and our realized crude oil price per barrel for year to date 2015 was $8.54 per barrel compared to $10.60 for year to date 2014. The improved differential was due in part to increased availability and use of pipeline transportation in the current year to move our crude oil to market with less dependence on more costly rail transportation.

Our average natural gas sales price for year to date 2015 decreased to $2.39 per Mcf compared to $5.80 for year to date 2014 due to lower market prices for natural gas and NGLs. Our natural gas production is primarily sold at the wellhead with price realizations being impacted by the volume and value of NGLs that purchasers extract from our sales stream. The difference between our realized natural gas sales prices and NYMEX Henry Hub calendar month natural gas prices was a discount of $0.39 per Mcf for year to date 2015 compared to a premium of $1.28 for the comparable 2014 period. NGL prices in 2015 have remained depressed in conjunction with low crude oil prices, which has reduced the value of our natural gas sales stream and unfavorably impacted the difference between our realized prices and Henry Hub benchmark pricing.

Crude oil, natural gas and NGL prices remain volatile and we are unable to predict the impact future price changes may have on our revenues and differentials for the remainder of 2015 and beyond.

Our sales volumes for year to date 2015 increased 14,802 MBoe, or 33%, over the comparable period in 2014 primarily due to an increase in producing wells resulting from the success of our drilling programs in North Dakota Bakken and

SCOOP. 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. Operating efficiencies achieved during 2015 on new third party pipeline systems provided for improved transportation of our crude oil to market, which resulted in the sale of crude oil previously stored in inventory and caused crude oil sales volumes to be higher than crude oil production by 86 MBbls for year to date 2015.

Derivatives. Changes in commodity prices during the nine months ended September 30, 2015 had a favorable impact on the fair value of our derivatives, which resulted in positive revenue adjustments of $74.5 million for the period. The following table presents cash settlements on matured derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented.

	Nine months ended September 30,	
In thousands	2015	2014
Cash received (paid) on derivatives:		
Crude oil derivatives	$—	$(79,418)
Natural gas derivatives	48,534	(17,799)
Cash received (paid) on derivatives, net	48,534	(97,217)
Non-cash gain on derivatives:		
Crude oil derivatives	4,544	257,145
Natural gas derivatives	21,467	11,873
Non-cash gain on derivatives, net	26,011	269,018
Gain on derivative instruments, net	$74,545	$171,801

Operating Costs and Expenses

Production Expenses. Production expenses increased 4% from $258.8 million for year to date 2014 to $268.7 million for year to date 2015. This increase was primarily the result of an increase in the number of producing wells and resulting 33% increase in sales volumes over the prior year period partially offset by curtailed spending and reduced service costs being realized in conjunction with depressed commodity prices.

Production expense per Boe decreased to $4.45 for year to date 2015 compared to $5.69 for year to date 2014. This per Boe decrease resulted from curtailed spending and reduced service costs being realized in response to depressed commodity prices, a higher portion of our production coming from natural gas wells in the SCOOP area which typically have lower operating costs compared to other areas, and a 33% increase in sales volumes from new well completions.

Production Taxes and Other Expenses. Production taxes and other expenses decreased $115.1 million, or 42%, to $157.6 million for year to date 2015 compared to $272.7 million for year to date 2014 primarily due to lower crude oil and natural gas revenues resulting from the significant decrease in commodity prices over the prior year period. Production taxes as a percentage of crude oil and natural gas revenues were 7.8% for year to date 2015 compared to 8.1% for year to date 2014, the decrease of which resulted from 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. The following table shows the components of exploration expenses for the periods presented.

	Nine months ended September 30,	
In thousands	2015	2014
Geological and geophysical costs	$6,497	$20,390
Exploratory dry hole costs	8,183	9,142
Exploration expenses	$14,680	$29,532

The decrease in geological and geophysical expenses in 2015 was due to changes in the timing and amount of costs incurred by the Company and recouped from joint interest partners between periods.

Dry hole costs incurred in 2015 primarily reflect costs associated with an unsuccessful well in an exploratory prospect in our North region.

Depreciation, Depletion, Amortization and Accretion. Total DD&A increased $324.9 million, or 34%, to $1.3 billion for year to date 2015 compared to $963.4 million for the comparable period in 2014 primarily due to a 33% increase in sales volumes. The following table shows the components of our DD&A on a unit of sales basis.

	Nine months ended September 30,	
$/Boe	2015	2014
Crude oil and natural gas	$20.98	$20.80
Other equipment	0.32	0.31
Asset retirement obligation accretion	0.06	0.06
Depreciation, depletion, amortization and accretion	$21.36	$21.17

The increase in our DD&A rate for crude oil and natural gas properties in the current period resulted from downward revisions of proved reserves in 2015 prompted by depressed commodity prices. If commodity prices remain at current levels or decline further, additional revisions of proved reserves may occur in the future, which may be significant and would result in a further increase in our DD&A rate. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on our future DD&A rate.

Property Impairments. Total property impairments increased $98.0 million, or 44%, to $321.1 million for year to date 2015 compared to $223.1 million for year to date 2014.

Impairments of proved properties increased $42.0 million for year to date 2015 to $111.3 million compared to $69.3 million for year to date 2014 due to higher write-downs resulting from declines in commodity prices in 2015 that adversely impacted the recoverability of capitalized costs in certain operating areas. The 2015 impairments were primarily concentrated in an emerging area with minimal production and costly reserve additions ($42.5 million), the Buffalo Red River units ($26.3 million), the Medicine Pole Hills units ($22.9 million), various non-core areas in the South region ($11.4 million), and non-Bakken areas of North Dakota and Montana ($8.2 million).

If commodity prices remain at current levels or decline further, downward revisions of reserves may be significant in the future and could result in additional impairments of proved properties in the remainder of 2015. We are unable to predict the timing and amount of future reserve revisions or the impact such revisions may have on future impairments, if any.

Impairments of non-producing properties increased $56.1 million for year to date 2015 to $209.8 million compared to $153.7 million for year to date 2014. The increase was primarily the result of higher rates of amortization being applied to undeveloped leasehold costs resulting from changes in the Company's estimates of undeveloped properties not expected to be developed before lease expiration, particularly in response to decreased commodity prices which have altered our drilling plans. Our rates of amortization may continue to increase in future periods if commodity prices remain at current levels or decline further and additional changes are made to drilling plans.

General and Administrative Expenses. G&A expenses increased $9.0 million, or 7%, to $143.4 million for year to date 2015 from $134.4 million for the comparable period in 2014 primarily due to an increase in personnel costs associated with our growth. G&A expenses include non-cash charges for equity compensation of $40.3 million and $39.4 million for year to date 2015 and year to date 2014, respectively.

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

	Nine months ended September 30,	
$/Boe	2015	2014
General and administrative expenses	$1.71	$2.08
Non-cash equity compensation	0.67	0.87
Total general and administrative expenses	$2.38	$2.95

The decrease in G&A expenses on a per-Boe basis in 2015 was driven by a 33% increase in sales volumes from new well completions.

The decrease in equity compensation expense on a per-Boe basis was due to an increase in the estimated rate of forfeitures of unvested restricted stock based on historical experience, which resulted in lower recognition of expense in 2015, coupled with the increase in sales volumes from new well completions with no comparable increase in equity compensation expense.

Interest Expense. Year to date interest expense increased $23.2 million, or 11%, to $232.9 million compared to $209.7 million for the comparable 2014 period due to an increase in our weighted average outstanding long-term debt obligations. Our weighted average outstanding long-term debt balance for year to date 2015 was approximately $6.8 billion with a weighted average interest rate of 4.4% compared to averages of $5.5 billion and 4.9% for the comparable period in 2014. The increase in outstanding debt resulted from borrowings incurred subsequent to September 30, 2014 to fund our 2014 and 2015 capital programs.

Income Taxes. We recorded an income tax benefit for the nine months ended September 30, 2015 of $98.6 million compared to income tax expense of $507.0 million for the prior year period, resulting in effective tax rates of approximately 32% and 37%, respectively, after taking into account permanent taxable differences and valuation allowances. For year to date 2015, we provided for income taxes at a combined federal and state tax rate of 38% of pre-tax losses generated by our operations in the United States. Our 2015 effective tax rate was impacted by a $13.3 million valuation allowance recognized against deferred tax assets associated with operating loss carryforwards generated by our Canadian subsidiary in 2015 for which we do not believe we will realize a benefit.

Liquidity and Capital Resources

Our primary sources of liquidity have historically been cash flows generated from operating activities, financing provided by our credit facility and the issuance of debt and equity securities. At September 30, 2015, we had $17.0 million of cash and cash equivalents and $1.15 billion of borrowing availability on our credit facility after considering $1.35 billion of outstanding borrowings and letters of credit. At November 4, 2015, outstanding borrowings totaled $880 million with $1.87 billion of borrowing availability on our credit facility. See Note 11. Subsequent Events in Notes to Unaudited Condensed Consolidated Financial Statements for a discussion of events occurring after September 30, 2015 that impacted our credit facility borrowings and availability.

Based on our planned capital expenditures, our forecasted operating cash flows and projected levels of indebtedness, we expect to maintain compliance with the covenants under our credit facility and senior note indentures for at least the next 12 months. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties as of September 30, 2015, including those described in Note 7. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements, recognizing we may be required to meet such commitments even if our business plan assumptions were to change.

Cash Flows

Cash flows from operating activities

Our net cash provided by operating activities was $1.42 billion and $2.28 billion for the nine months ended September 30, 2015 and 2014, respectively. The decrease in operating cash flows was primarily due to lower crude oil and natural gas revenues driven by lower realized commodity prices along with increases in production expenses and interest expense associated with the growth of our Company and an increase in producing well count over the past year, all partially offset by lower production taxes and an increase in cash gains on matured derivatives. We expect our operating cash flows for the remainder of 2015 will continue to be significantly lower than 2014 levels given the current commodity price environment.

Cash flows used in investing activities

During the nine months ended September 30, 2015 and 2014, we had cash flows used in investing activities (excluding proceeds from asset sales) of $2.63 billion and $3.36 billion, respectively, related to our capital program, inclusive of dry hole costs and property acquisitions. Cash acquisition capital expenditures totaled $43.2 million and $179.8 million for the nine months ended September 30, 2015 and 2014, respectively. Cash capital expenditures excluding acquisitions totaled $2.59 billion and $3.18 billion for the nine months ended September 30, 2015 and 2014, respectively, the decrease of which was driven by a decrease in our capital budget and related drilling activity for 2015. Our cash capital expenditures for 2015 include the payment of amounts owed at December 31, 2014 in connection with our 2014 drilling program and associated $482.5 million decrease in accruals for capital expenditures for the nine months ended September 30, 2015.

The use of cash for capital expenditures in 2015 and 2014 was partially offset by proceeds received from asset dispositions, which totaled $33.2 million and $129.3 million for the nine months ended September 30, 2015 and 2014, respectively.

Cash flows from financing activities

Net cash provided by financing activities for the nine months ended September 30, 2015 was $1.18 billion primarily resulting from net borrowings incurred on our credit facility during the period. Our 2015 operating cash flows were adversely impacted by decreased commodity prices, leading to a $1.18 billion net increase in credit facility borrowings incurred for the payment of amounts owed in connection with our 2014 drilling program and to fund a portion of our 2015 drilling program.

Net cash provided by financing activities for the nine months ended September 30, 2014 was $1.07 billion primarily resulting from the receipt of $1.68 billion of net proceeds from the issuances of $1.0 billion of 3.8% Senior Notes due 2024 and $700 million of 4.9% Senior Notes due 2044 in May 2014, partially offset by net repayments of $275 million on our credit facility and the July 2014 redemption of our 8.25% Senior Notes due 2019 for $317.5 million.

Future Sources of Financing

Although we cannot provide any assurance, we believe funds from operating cash flows, our remaining cash balance and availability under 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 at least the next 12 months. Our capital expenditures budget for the remainder of 2015 is reflective of the depressed commodity price environment and has been established based on an expectation of available cash flows from operations and availability under our credit facility. If operating cash flows are materially impacted by a further decline in commodity prices, we have the ability to reduce our capital expenditures further or utilize the availability on our credit facility if needed to fund our operations. On November 4, 2015 we refinanced $500 million of our outstanding credit facility borrowings into a new term loan, and we may choose to access the capital markets for additional financing or capital to take advantage of business opportunities that may arise if such financing can be arranged on favorable terms. Additionally, we may choose to sell assets to obtain funding for our operations and capital program.

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, which had aggregate lender commitments totaling $2.75 billion at November 4, 2015, which may be increased up to a total of $4.0 billion upon agreement between the Company and participating lenders. The commitments are from a syndicate of 17 banks and financial institutions. We believe each member of the current syndicate has the capability to fund its commitment. As of November 4, 2015, we had $880 million of outstanding borrowings and $1.87 billion of borrowing availability on our credit facility after considering outstanding borrowings, letters of credit, and events occurring after September 30, 2015 that impacted our credit facility borrowings and availability as discussed in Note 11. Subsequent Events in Notes to Unaudited Condensed Consolidated Financial Statements.

The commitments under our credit facility are not dependent on a borrowing base calculation subject to periodic redetermination based on changes in commodity prices and proved reserves. Additionally, a downgrade or other negative rating action with respect to our credit rating will not trigger a reduction in our current credit facility commitments, nor will such action trigger a security requirement or change in covenants.

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 consolidated net debt to total 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 plus, to the extent resulting in a reduction of total shareholders’ equity, the amount of any non-cash impairment charges incurred, net of any tax effect, after June 30, 2014.

We were in compliance with our credit facility covenants at September 30, 2015 and expect to maintain compliance for at least the next 12 months. At September 30, 2015, our consolidated net debt to total capitalization ratio, as defined in our credit facility as amended, was 0.57 to 1.00. We do not believe the credit facility covenants are reasonably likely to limit our ability to undertake additional debt or equity financing to a material extent. At September 30, 2015, our total debt would have needed to independently increase by approximately $2.7 billion, or 38%, above existing levels at that date (with no corresponding increase in cash or reduction in refinanced debt) to reach the maximum covenant ratio of 0.65 to 1.00. Alternatively, our total shareholders' equity would have needed to independently decrease by approximately $1.5 billion, or 31%, below existing levels at September 30, 2015 to reach the maximum covenant ratio. These independent point-in-time sensitivities do not take into account other factors that could arise to mitigate the impact of changes in debt and equity on our consolidated net debt to total capitalization ratio, such as disposing of assets or exploring alternative sources of capitalization.

Future Capital Requirements

Senior notes

Our long-term debt includes outstanding senior note obligations totaling $5.8 billion at September 30, 2015. We have no near-term senior note maturities, with our earliest scheduled maturity being our $200 million of 2020 Notes due in October 2020. Our senior notes are not subject to any mandatory redemption or sinking fund requirements. For further information on the face values, maturity dates, semi-annual interest payment dates, optional redemption periods and covenant restrictions related to our senior notes, refer to Note 6. Long-Term Debt in Notes to Unaudited Condensed Consolidated Financial Statements.

We were in compliance with our senior note covenants at September 30, 2015 and expect to maintain compliance for at least the next 12 months. We do not believe the senior note covenants will materially limit our ability to undertake additional debt or equity financing. A downgrade or other negative rating action with respect to the credit ratings assigned to our senior unsecured debt does not trigger additional senior note covenants that are more restrictive than the existing covenants at September 30, 2015.

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.

Term loan

On November 4, 2015, we entered into a $500 million term loan that matures in November 2018. See Note 11. Subsequent Events in Notes to Unaudited Condensed Consolidated Financial Statements for further information.

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 2015 is $2.7 billion excluding acquisitions, which is expected to be allocated as follows:

In millions	Amount
Exploration and development drilling	$2,370
Land costs	180
Capital facilities, workovers and other corporate assets	138
Seismic	12
Total 2015 capital budget, excluding acquisitions	$2,700

During the nine months ended September 30, 2015, we participated in the completion of 734 gross (235 net) wells and invested approximately $2,109.3 million in our capital program, excluding $43.2 million of unbudgeted acquisitions, excluding $482.5 million of capital costs associated with decreased accruals for capital expenditures, and including $3.9 million of seismic costs. Our 2015 year to date capital expenditures were allocated as follows by quarter:

In millions	1Q 2015	2Q 2015	3Q 2015	YTD 2015
Exploration and development drilling	$914.2	$518.3	$477.8	$1,910.3
Land costs	27.1	19.9	28.3	75.3
Capital facilities, workovers and other corporate assets	40.9	45.1	33.8	119.8
Seismic	1.6	2.2	0.1	3.9
Capital expenditures, excluding acquisitions	983.8	585.5	540.0	2,109.3
Acquisitions of producing properties	0.1	0.4	—	0.5
Acquisitions of non-producing properties	36.7	6.0	—	42.7
Total acquisitions	36.8	6.4	—	43.2
Total capital expenditures	$1,020.6	$591.9	$540.0	$2,152.5

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Our 2015 capital program is focused primarily on development drilling in the North Dakota Bakken and SCOOP plays, focusing on core areas of the plays that have the greatest potential to improve recoveries and rates of return. Our year to date capital expenditures incurred through September 30, 2015 are trending below budget resulting from measures taken to reduce capital spending to be aligned with operating cash flows in response to depressed commodity prices. We expect our 2015 fourth quarter non-acquisition capital expenditures will be between $350 million and $400 million.

Our 2015 capital program has been established based on an expectation of available cash flows from operations and availability under our credit facility. 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. We monitor our capital spending closely based on actual and projected cash flows and may continue to scale back our spending should commodity prices remain at current levels or decrease. 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

Refer to Note 7. Commitments and Contingencies in Notes to Unaudited Condensed Consolidated Financial Statements for a discussion of certain future commitments of the Company as of September 30, 2015. 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 our commitments.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resources. However, as is customary in the crude oil and natural gas industry, we have various contractual commitments not reflected in the consolidated balance sheets as shown in Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Contractual Obligations in our 2014 Form 10-K.

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our 2014 Form 10-K.

Non-GAAP Financial Measures

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

Management believes EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. Further, we believe EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. We exclude the items listed above from net income (loss) 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 (loss) 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 (loss) to EBITDAX for the periods presented.

	Three months ended September 30,		Nine months ended September 30,	
In thousands	2015	2014	2015	2014
Net income (loss)	$(82,423)	$533,521	$(213,992)	$863,293
Interest expense	79,399	73,912	232,904	209,728
Provision (benefit) for income taxes	(48,744)	313,340	(98,623)	507,015
Depreciation, depletion, amortization and accretion	448,809	363,677	1,288,278	963,409
Property impairments	96,697	85,561	321,130	223,085
Exploration expenses	232	13,514	14,680	29,532
Impact from derivative instruments:				
Total gain on derivatives, net	(46,527)	(473,999)	(74,545)	(171,801)
Cash received (paid) on derivatives, net	11,917	190	48,534	(97,217)
Non-cash gain on derivatives, net	(34,610)	(473,809)	(26,011)	(269,018)
Non-cash equity compensation	12,861	13,402	40,290	39,419
Loss on extinguishment of debt	—	24,517	—	24,517
EBITDAX	$472,221	$947,635	$1,558,656	$2,590,980

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

	Nine months ended September 30,	
In thousands	2015	2014
Net cash provided by operating activities	$1,415,492	$2,277,851
Current income tax provision	22	2,278
Interest expense	232,904	209,728
Exploration expenses, excluding dry hole costs	6,497	20,390
Gain (loss) on sale of assets, net	22,930	(952)
Excess tax benefit from stock-based compensation	13,177	—
Other, net	(8,023)	(12,850)
Changes in assets and liabilities	(124,343)	94,535
EBITDAX	$1,558,656	$2,590,980

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 seek to 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 prices we receive from sales of our crude oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for crude oil and natural gas has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index prices. Based on our average daily production for the nine months ended September 30, 2015, and excluding any effect of our derivative instruments in place, our annual revenue would increase or decrease by approximately $536 million for each $10.00 per barrel change in crude oil prices at September 30, 2015 and $161 million for each $1.00 per Mcf change in natural gas prices at September 30, 2015.

To reduce price risk caused by these market fluctuations, from time to time we may economically hedge a portion of our anticipated crude oil and natural gas production as part of our risk management program. In addition, we may utilize basis contracts to hedge the differential between derivative contract index prices and those of our physical pricing points. Reducing our exposure to price volatility helps secure funds for our capital program. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. We may choose not to hedge future production if the price environment for certain time periods is deemed to be unfavorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities in order to monetize favorable gain positions for the purpose of funding our capital program. While hedging, if utilized, limits the downside risk of adverse price movements, it also limits future revenues from upward price movements. Our crude oil production and sales for the remainder of 2015 and beyond are currently unhedged and directly exposed to continued volatility in crude oil market prices, whether favorable or unfavorable.

Changes in commodity prices during the nine months ended September 30, 2015 had an overall favorable impact on the fair value of our derivative instruments. For the nine months ended September 30, 2015, we recognized cash gains on derivatives of $48.5 million and non-cash mark-to-market gains on derivatives of $26.0 million.

The fair value of our crude oil derivative instruments at September 30, 2015 was a net liability of $0.2 million. An assumed increase in the forward prices used in the September 30, 2015 valuation of our crude oil derivatives of $10.00 per barrel would increase our crude oil derivative liability to approximately $0.6 million at September 30, 2015. Conversely, an assumed decrease in forward prices of $10.00 per barrel would decrease our crude oil derivative liability to approximately $0.1 million at September 30, 2015.

The fair value of our natural gas derivative instruments at September 30, 2015 was a net asset of $105.9 million. An assumed increase in the forward prices used in the September 30, 2015 valuation of our natural gas derivatives of $1.00 per MMBtu would change our derivative valuation to a net liability of approximately $9.4 million at September 30, 2015. Conversely, an assumed decrease in forward prices of $1.00 per MMBtu would increase our natural gas derivative asset to approximately $222.9 million at September 30, 2015.

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, crude oil refining companies, and natural gas gathering and processing companies ($429 million in receivables at September 30, 2015), our joint interest receivables ($355 million at September 30, 2015), and counterparty credit risk associated with our derivative instrument receivables ($106 million at September 30, 2015).

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 the individuals and entities who own a partial interest in the wells we operate. These individuals and 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 this 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 $40 million at September 30, 2015, which will be used to offset future capital costs when billed. In this manner, we reduce credit risk. We may 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.

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. See Note 11. Subsequent Events in Notes to Unaudited Condensed Consolidated Financial Statements for a discussion of events occurring after September 30, 2015 that impacted our credit facility borrowings and availability. We had $880 million of outstanding borrowings on our credit facility at November 4, 2015 with a weighted average interest rate of 1.7%. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $8.8 million per year and a $5.5 million decrease in net income per year.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation of the effectiveness of the design and operation of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) was performed under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that the Company’s disclosure controls and procedures were effective as of September 30, 2015 to ensure that information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and that information required to be disclosed under the Exchange Act is accumulated and communicated to the Company’s management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the three months ended September 30, 2015, 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

In November 2010, a putative class action was filed in the District Court of Blaine County, Oklahoma by Billy J. Strack and Daniela A. Renner as trustees of certain named trusts and on behalf of other similarly situated parties against the Company. The Petition alleged the Company improperly deducted post-production costs from royalties paid to plaintiffs and other royalty interest owners from crude oil and natural gas wells located in Oklahoma. The plaintiffs 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 proposed class. On November 3, 2014, plaintiffs filed an Amended Petition that did not add any substantive claims, but sought a "hybrid class action" in which they sought certification of certain claims for injunctive relief, reserving the right to seek a further class certification on money damages in the future. Plaintiffs filed an Amended Motion for Class Certification on January 9, 2015, that modified the proposed class to royalty owners in Oklahoma production from July 1, 1993, to the present (instead of 1980 to the present) and sought certification of over 45 separate "issues" for injunctive or declaratory relief, again, reserving the right to seek a further class certification of money damages in the future. The Company responded to the petition, its amendment, and the motions for class certification denying the allegations and raising a number of affirmative defenses and legal arguments to each of the claims and filings. Certain discovery was undertaken and the "hybrid" motion was briefed by plaintiffs and the Company. A hearing on the "hybrid" class certification was held on June 1st and 2nd, 2015. On June 11, 2015, the trial court certified a "hybrid" class as requested by plaintiffs. The Company has appealed the trial court's class certification order, which will be reviewed de novo by the appellate court. A mediation is scheduled for December 7, 2015. 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. Although not currently at issue in the "hybrid" certification, plaintiffs have alleged underpayments in excess of $200 million that they may claim as damages, 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 will continue to assert its defenses to the case as certified as well as any future attempt to certify a money damages class.

ITEM 1A. Risk Factors

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 2014 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 2014 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.
There have been no material changes in our risk factors from those disclosed in our 2014 Form 10-K.

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 shares of our common stock during the three months ended September 30, 2015:

Period	Total number of shares purchased (1)	Average price paid per share (2)	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs

				(3)
July 1, 2015 to July 31, 2015	—	$—	—	—
August 1, 2015 to August 31, 2015	18,846	33.18	—	—
September 1, 2015 to September 30, 2015	—	—	—	—
Total	18,846	$33.18	—	—

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(1) In connection with restricted stock grants under the Company's 2005 Long-Term Incentive Plan and 2013 Long-Term Incentive Plan, we adopted a policy that enables employees to surrender shares to cover their tax liability. Shares indicated as having been purchased in the table above represent shares surrendered by employees to cover tax liabilities. We paid the associated taxes to the Internal Revenue Service.

(2) The price paid per share was the closing price of our common stock on the date the restrictions lapsed on such shares.

(3) We are unable to determine at this time the total amount of securities or approximate dollar value of securities that could potentially be surrendered to us pursuant to our policy that enables employees to surrender shares to cover their tax liability associated with the vesting of restrictions on shares.

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

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

SIGNATURE

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

CONTINENTAL RESOURCES, INC.

Date: November 4, 2015

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	Conformed version of Third Amended and Restated Certificate of Incorporation of Continental Resources, Inc. as amended by amendment filed on June 15, 2015 filed as Exhibit 3.1 to the Company's Current Report on Form 10-Q (Commission File No. 001-32886) filed August 5, 2015 and incorporated herein by reference.
3.2	Third Amended and Restated Bylaws of Continental Resources, Inc. filed as Exhibit 3.1 to the Company's Current Report on Form 8-K (Commission File No. 001-32886) filed November 6, 2012 and incorporated herein by reference.
10.1*	Term Loan Agreement dated as of November 4, 2015 among Continental Resources, Inc., as borrower, and its subsidiaries Banner Pipeline Company, L.L.C. and CLR Asset Holdings, LLC, as guarantors, and MUFG Union Bank, N.A., as Administrative Agent, Bank of America, N.A., Citibank, N.A., JPMorgan Chase Bank, N.A. and Mizuho Bank, LTD., as Co-Syndication Agents, and Compass Bank, Toronto Dominion (Texas) LLC and U.S. Bank National Association, as Co-Documentation Agents, and the other lenders party thereto.
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