WHITING PETROLEUM CORP
Form 10-Q
October 26, 2017
UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 Q

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

For the quarterly period ended September 30, 2017

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 31899

WHITING PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20 0098515 (I.R.S. Employer Identification No.)
	80290 2300

1700 Broadway, Suite 2300
Denver, Colorado
(Address of principal executive offices) (Zip code)

(303) 837 1661
(Registrant's telephone number, including area code)

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 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 No

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

Number of shares of the registrant's common stock outstanding at October 13, 2017: 362,793,720 shares.

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Glossary of Certain Definitions

Unless the context otherwise requires, the terms “we”, “us”, “our” or “ours” when used in this Quarterly Report on Form 10-Q refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this report:

“ASC” Accounting Standards Codification.

“Bbl” One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

“Bcf” One billion cubic feet, used in reference to natural gas.

“BOE” One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

“Btu” or “British thermal unit” The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit.

“CO2” Carbon dioxide.

“completion” The process of preparing an oil and gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production.

“costless collar” An option position where the proceeds from the sale of a call option at its inception fund the purchase of a put option at its inception.

“deterministic method” The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

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

“differential” The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

“dry hole” A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

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

“FASB” Financial Accounting Standards Board.

“field” An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

“GAAP” Generally accepted accounting principles in the United States of America.

“gross acres” or “gross wells” The total acres or wells, as the case may be, in which a working interest is owned.

“ISDA” International Swaps and Derivatives Association, Inc.

“lease operating expense” or “LOE” The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

“LIBOR” London interbank offered rate.

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"MBbl" One thousand barrels of oil, NGLs or other liquid hydrocarbons.

"MBbl/d" One MBbl per day.

"MBOE" One thousand BOE.

"MBOE/d" One MBOE per day.

"Mcf" One thousand cubic feet, used in reference to natural gas.

"MMBbl" One million Bbl.

"MMBOE" One million BOE.

"MMBtu" One million British Thermal Units, used in reference to natural gas.

"MMcf" One million cubic feet, used in reference to natural gas.

"MMcf/d" One MMcf per day.

"net acres" or "net wells" The sum of the fractional working interests owned in gross acres or wells, as the case may be.

"net production" The total production attributable to our fractional working interest owned.

"NGL" Natural gas liquid.

"NYMEX" The New York Mercantile Exchange.

"plug-and-perf technology" A horizontal well completion technique in which hydraulic fractures are performed in multiple stages, with each stage utilizing a bridge plug to divert fracture stimulation fluids through the casing perforations into the formation within that stage.

"plugging and abandonment" Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of most states legally require plugging of abandoned wells.

"prospect" A property on which indications of oil or gas have been identified based on available seismic and geological information.

"proved developed reserves" Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

"proved reserves" Those reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any, and
b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and
b. The project has been approved for development by all necessary parties and entities, including governmental entities.

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Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"reasonable certainty" If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"reserves" Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"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 individual and separate from other reservoirs.

"royalty" The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

"SEC" The United States Securities and Exchange Commission.

"working interest" The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

"workover" Operations on a producing well to restore or increase production.

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PART I – FINANCIAL INFORMATION

Item 1. Condensed Consolidated Financial Statements

WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (unaudited)

(in thousands, except share and per share data)

	September 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 11,172	$ 55,975
Restricted cash	-	17,250
Accounts receivable trade, net	225,291	173,919
Prepaid expenses and other	32,734	26,312
Assets held for sale	-	349,146
Total current assets	269,197	622,602
Property and equipment:		
Oil and gas properties, successful efforts method	12,797,474	13,230,851
Other property and equipment	134,502	134,638
Total property and equipment	12,931,976	13,365,489
Less accumulated depreciation, depletion and amortization	(4,734,351)	(4,222,071)
Total property and equipment, net	8,197,625	9,143,418
Other long-term assets	35,756	110,122
TOTAL ASSETS	$ 8,502,578	$ 9,876,142
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 65,016	$ 32,126
Revenues and royalties payable	130,447	147,226
Accrued capital expenditures	107,706	56,830
Accrued interest	24,124	44,749
Accrued lease operating expenses	37,554	45,015
Accrued liabilities and other	23,066	63,538
Taxes payable	23,096	39,547
Derivative liabilities	25,145	17,628
Accrued employee compensation and benefits	23,297	31,134

Liabilities related to assets held for sale	-	538
Total current liabilities	459,451	478,331
Long-term debt	2,931,443	3,535,303
Deferred income taxes	162,054	475,689
Asset retirement obligations	157,298	168,504
Other long-term liabilities	76,359	69,123
Total liabilities	3,786,605	4,726,950
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 600,000,000 shares authorized; 368,020,048 issued and 362,793,720 outstanding as of September 30, 2017 and 367,174,542 issued and 362,013,928 outstanding as of December 31, 2016	368	367
Additional paid-in capital	6,403,767	6,389,435
Accumulated deficit	(1,688,162)	(1,248,572)
Total Whiting shareholders' equity	4,715,973	5,141,230
Noncontrolling interest	-	7,962
Total equity	4,715,973	5,149,192
TOTAL LIABILITIES AND EQUITY	$ 8,502,578	$ 9,876,142

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

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WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
OPERATING REVENUES				
Oil, NGL and natural gas sales	$ 324,191	$ 315,554	$ 1,007,023	$ 942,287
OPERATING EXPENSES				
Lease operating expenses	90,615	87,982	267,277	307,530
Production taxes	27,499	26,372	86,621	79,125
Depreciation, depletion and amortization	212,846	284,569	673,288	900,877
Exploration and impairment	17,657	24,293	63,793	85,565
General and administrative	30,084	33,908	92,644	112,227
Derivative (gain) loss, net	30,867	(30,432)	47,281	(28,432)
Loss on sale of properties	398,752	189,934	401,050	193,729
Amortization of deferred gain on sale	(3,175)	(3,490)	(9,757)	(11,111)
Total operating expenses	805,145	613,136	1,622,197	1,639,510
LOSS FROM OPERATIONS	(480,954)	(297,582)	(615,174)	(697,223)
OTHER INCOME (EXPENSE)				
Interest expense	(47,693)	(84,578)	(143,641)	(245,145)
Gain (loss) on extinguishment of debt	-	46,541	(1,540)	(42,236)
Interest income and other	(83)	115	970	1,146
Total other expense	(47,776)	(37,922)	(144,211)	(286,235)
LOSS BEFORE INCOME TAXES	(528,730)	(335,504)	(759,385)	(983,458)
INCOME TAX EXPENSE (BENEFIT)				
Current	(3,161)	113	(6,367)	115
Deferred	(239,137)	357,438	(313,634)	182,286
Total income tax expense (benefit)	(242,298)	357,551	(320,001)	182,401
NET LOSS	(286,432)	(693,055)	(439,384)	(1,165,859)
Net loss attributable to noncontrolling interests	-	3	14	18
NET LOSS ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ (286,432)	$ (693,052)	$ (439,370)	$ (1,165,841)
LOSS PER COMMON SHARE				
Basic	$ (0.79)	$ (2.47)	$ (1.21)	$ (4.92)
Diluted	$ (0.79)	$ (2.47)	$ (1.21)	$ (4.92)
WEIGHTED AVERAGE SHARES OUTSTANDING				
Basic	362,794	280,418	362,713	237,100

Diluted	362,794	280,418	362,713	237,100

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

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WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (439,384)	$ (1,165,859)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	673,288	900,877
Deferred income tax expense (benefit)	(313,634)	182,286
Amortization of debt issuance costs, debt discount and debt premium	22,927	72,389
Stock-based compensation	19,051	19,512
Amortization of deferred gain on sale	(9,757)	(11,111)
Loss on sale of properties	401,050	193,729
Undeveloped leasehold and oil and gas property impairments	44,270	45,906
Exploratory dry hole costs	-	37
Loss on extinguishment of debt	1,540	42,236
Non-cash derivative loss	57,937	102,100
Other, net	(7,008)	(4,732)
Changes in current assets and liabilities:		
Accounts receivable trade, net	(51,319)	119,622
Prepaid expenses and other	(6,441)	9,063
Accounts payable trade and accrued liabilities	(68,881)	(104,579)
Revenues and royalties payable	(16,782)	(41,336)
Taxes payable	(16,451)	(1,885)
Net cash provided by operating activities	290,406	358,255
CASH FLOWS FROM INVESTING ACTIVITIES		
Drilling and development capital expenditures	(616,753)	(434,794)
Acquisition of oil and gas properties	(18,452)	(3,605)
Other property and equipment	(3,371)	(6,744)
Proceeds from sale of oil and gas properties	916,176	304,291
Net cash provided by (used in) investing activities	277,600	(140,852)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings under credit agreement	1,630,000	1,050,000
Repayments of borrowings under credit agreement	(1,980,000)	(1,200,000)
Redemption of 6.5% Senior Subordinated Notes due 2018	(275,121)	-
Early conversion payments for New Convertible Notes	-	(41,919)
Debt issuance costs	-	(22,499)
Restricted stock used for tax withholdings	(4,938)	(709)

Net cash used in financing activities	$ (630,059)	$ (215,127)

(Continued)

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WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2017	2016
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	$ (62,053)	$ 2,276
CASH, CASH EQUIVALENTS AND RESTRICTED CASH		
Beginning of period	73,225	16,053
End of period	$ 11,172	$ 18,329
NONCASH INVESTING ACTIVITIES		
Accrued capital expenditures and accounts payable related to property additions	$ 147,084	$ 62,416
NONCASH FINANCING ACTIVITIES (1)		

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

(1) Refer to the "Long-Term Debt" footnote in the notes to condensed consolidated financial statements for a discussion of (i) the Company's exchange of senior notes and senior subordinated notes for convertible notes and the subsequent conversions of such notes, and (ii) the Company's exchange of senior notes, convertible senior notes and senior subordinated notes for mandatory convertible notes and the subsequent conversions of such notes.

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WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY (unaudited)

(in thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Whiting Shareholders' Equity	Noncontrolling Interest	Total Equity
BALANCES - January 1, 2016	206,441	$ 206	$ 4,659,868	$ 90,530	$ 4,750,604	$ 7,984	$ 4,758,588
Net loss	-	-	-	(1,165,841)	(1,165,841)	(18)	(1,165,859)
Issuance of common stock upon conversion of convertible notes	79,920	80	822,936	-	823,016	-	823,016
Reduction of equity component of 2020 Convertible Senior Notes upon extinguishment, net	-	-	(63,330)	-	(63,330)	-	(63,330)
Recognition of beneficial conversion features on convertible notes	-	-	232,801	-	232,801	-	232,801
Restricted stock issued	4,021	4	(4)	-	-	-	-
Restricted stock forfeited	(615)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(90)	-	(709)	-	(709)	-	(709)
Stock-based compensation	-	-	19,512	-	19,512	-	19,512
BALANCES - September 30, 2016	289,677	$ 290	$ 5,671,074	$ (1,075,311)	$ 4,596,053	$ 7,966	$ 4,604,019
BALANCES - January 1, 2017	367,175	$ 367	$ 6,389,435	$ (1,248,572)	$ 5,141,230	$ 7,962	$ 5,149,192
Net loss	-	-	-	(439,370)	(439,370)	(14)	(439,384)
	-	-	-	-	-	(7,948)	(7,948)

Conveyance of third party ownership interest in Sustainable Water Resources, LLC							
Restricted stock issued	2,271	2	(2)	-	-	-	-
Restricted stock forfeited	(1,022)	(1)	1	-	-	-	-
Restricted stock used for tax withholdings	(404)	-	(4,938)	-	(4,938)	-	(4,938)
Stock-based compensation	-	-	19,051	-	19,051	-	19,051
Cumulative effect of change in accounting principle	-	-	220	(220)	-	-	-
BALANCES - September 30, 2017	368,020	$ 368	$ 6,403,767	$ (1,688,162)	$ 4,715,973	$ -	$ 4,715,973

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

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WHITING PETROLEUM CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. BASIS OF PRESENTATION

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company engaged in the development, production, acquisition and exploration of crude oil, NGLs and natural gas primarily in the Rocky Mountains region of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to "Whiting" or the "Company" are to Whiting Petroleum Corporation and its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), Whiting US Holding Company, Whiting Canadian Holding Company ULC (formerly Kodiak Oil & Gas Corp., "Kodiak"), Whiting Resources Corporation and Whiting Programs, Inc.

Condensed Consolidated Financial Statements—The unaudited condensed consolidated financial statements include the accounts of Whiting Petroleum Corporation and its consolidated subsidiaries. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company's equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation. These financial statements have been prepared in accordance with GAAP and the SEC rules and regulations for interim financial reporting. In the opinion of management, the accompanying financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company's interim results. However, operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year. The condensed consolidated financial statements and related notes included in this Quarterly Report on Form 10-Q should be read in conjunction with Whiting's consolidated financial statements and related notes included in the Company's Annual Report on Form 10-K for the period ended December 31, 2016. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to consolidated financial statements included in the Company's 2016 Annual Report on Form 10 K.

Reclassifications—Certain prior period balances in the condensed consolidated balance sheets and statements of operations have been reclassified to conform to the current year presentation. Such reclassifications had no impact on net income, cash flows or shareholders' equity previously reported.

Adopted and Recently Issued Accounting Pronouncements—In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers ("ASU 2014 09"). The objective of ASU 2014-09 is to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and International Financial Reporting Standards. The FASB subsequently issued various ASUs which deferred the effective date of ASU 2014-09 and provided additional implementation guidance. ASU 2014-09 and its amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The standards permit retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented or (ii) recognition of a cumulative-effect adjustment as of the date of initial application. The Company plans to adopt these ASUs effective January 1, 2018 using the modified retrospective approach. The Company is in the process of assessing its contracts with customers and evaluating the effect of adopting these standards on its financial statements, accounting policies and internal controls. The adoption is not expected to have a significant impact on the Company's net income or cash flows, however, the Company is currently evaluating the proper classification of certain pipeline gathering and transportation agreements as well as gas processing agreements to determine whether changes to total revenues and expenses will be necessary under the new standards. In addition, the Company is also currently assessing the additional disclosures that will be required upon implementation of these ASUs.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases ("ASU 2016-02"). The objective of this ASU is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. ASU 2016-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 and should be applied using a modified retrospective approach. Early adoption is permitted. Although the Company is still in the process of evaluating the effect of adopting ASU 2016 02, the adoption is expected to result in (i) an increase in the assets and liabilities recorded on its consolidated balance sheet, (ii) an increase in depreciation, depletion and amortization expense and interest expense recorded on its consolidated statement of operations, and (iii) additional disclosures. As of September 30, 2017, the Company had approximately $87 million of contractual obligations related to its non-cancelable leases, drilling rig contracts and pipeline transportation agreements, and it will evaluate those contracts as well as other existing arrangements to determine if they qualify for lease accounting under ASU 2016-02.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"). The objective of this ASU is to simplify several aspects of the accounting for employee share-based payment transactions, including income tax consequences, forfeitures, classification of awards as either equity or liabilities and classification in the statement of cash flows. Portions of this ASU must be applied prospectively while other portions may be applied either prospectively or retrospectively. ASU 2016-09 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, and the Company adopted this standard on January 1, 2017. Upon adoption of ASU 2016-09, the Company (i) recorded $70 million of previously unrecognized excess tax benefits on a modified retrospective basis with a full valuation allowance, resulting in a net cumulative-effect adjustment to retained earnings of zero, (ii) prospectively removed excess tax benefits from its calculation of diluted shares, which had no impact on the Company's diluted earnings per share for the three and nine months ended September 30, 2017, and (iii) elected to account for forfeitures of share-based awards as they occur, rather than by applying an estimated forfeiture rate to determine compensation expense, the effect of which was recognized using a modified retrospective approach and resulted in an immaterial cumulative-effect adjustment to retained earnings and additional paid-in capital.

2. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company's oil and gas producing activities at September 30, 2017 and December 31, 2016 are as follows (in thousands):

	September 30, 2017	December 31, 2016
Proved leasehold costs	$ 2,658,889	$ 3,330,928
Unproved leasehold costs	191,067	392,484
Costs of completed wells and facilities	9,432,776	9,016,472
Wells and facilities in progress	514,742	490,967
Total oil and gas properties, successful efforts method	12,797,474	13,230,851
Accumulated depletion	(4,676,819)	(4,170,237)
Oil and gas properties, net	$ 8,120,655	$ 9,060,614

3. ACQUISITIONS AND DIVESTITURES

2017 Acquisitions and Divestitures

On September 1, 2017, the Company completed the sale of its interests in certain producing oil and gas properties located in the Fort Berthold Indian Reservation area in Dunn and McLean counties of North Dakota, as well as other related assets and liabilities, (the "FBIR Assets") for aggregate sales proceeds of $500 million (before closing adjustments). The sale was effective September 1, 2017 and resulted in a pre-tax loss on sale of $402 million. The Company used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

On January 1, 2017, the Company completed the sale of its 50% interest in the Robinson Lake gas processing plant located in Mountrail County, North Dakota and its 50% interest in the Belfield gas processing plant located in Stark County, North Dakota, as well as the associated natural gas, crude oil and water gathering systems, effective January 1, 2017, for aggregate sales proceeds of $375 million (before closing adjustments). The Company used the net proceeds from this transaction to repay a portion of the debt outstanding under its credit agreement.

The following table shows the components of assets and liabilities classified as held for sale as of December 31, 2016 (in thousands):

	Carrying Value as of December 31, 2016
Assets	
Oil and gas properties, net	$ 347,817
Other property and equipment, net	475
Total property and equipment, net	348,292
Other long-term assets	854
Total assets held for sale	$ 349,146
Liabilities	
Asset retirement obligations	$ 131
Other long-term liabilities	407
Total liabilities related to assets held for sale	$ 538

There were no significant acquisitions during the nine months ended September 30, 2017.

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2016 Acquisitions and Divestitures

In July 2016, the Company completed the sale of its interest in its enhanced oil recovery project in the North Ward Estes field in Ward and Winkler counties of Texas, including Whiting's interest in certain CO2 properties in the McElmo Dome field in Colorado and certain other related assets and liabilities (the "North Ward Estes Properties") for a cash purchase price of $300 million (before closing adjustments). The sale was effective July 1, 2016 and resulted in a pre-tax loss on sale of $187 million. The Company used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

In addition to the cash purchase price, the buyer agreed to pay Whiting $100,000 for every $0.01 that, as of June 28, 2018, the average NYMEX crude oil futures contract price for each month from August 2018 through July 2021 is above $50.00/Bbl up to a maximum amount of $100 million (the "Contingent Payment"). The Company determined that this Contingent Payment was an embedded derivative and reflected it at fair value in the consolidated financial statements prior to settlement. On July 19, 2017, the buyer paid $35 million to Whiting to settle this Contingent Payment, resulting in a pre-tax gain of $3 million. Refer to the "Derivative Financial Instruments" and "Fair Value Measurements" footnotes for more information on this embedded derivative instrument.

There were no significant acquisitions during the year ended December 31, 2016.

4. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2017 and December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Credit agreement	$ 200,000	$ 550,000
6.5% Senior Subordinated Notes due 2018	-	275,121
5.0% Senior Notes due 2019	961,409	961,409
1.25% Convertible Senior Notes due 2020	562,075	562,075
5.75% Senior Notes due 2021	873,609	873,609
6.25% Senior Notes due 2023	408,296	408,296
Total principal	3,005,389	3,630,510
Unamortized debt discounts and premiums	(56,151)	(71,340)
Unamortized debt issuance costs on notes	(17,795)	(23,867)
Total long-term debt	$ 2,931,443	$ 3,535,303

Credit Agreement

Whiting Oil and Gas, the Company's wholly owned subsidiary, has a credit agreement with a syndicate of banks that as of September 30, 2017 had a borrowing base and aggregate commitments of $2.5 billion. As of September 30, 2017, the Company had $2.3 billion of available borrowing capacity, which was net of $200 million in borrowings and $9 million in letters of credit outstanding.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company's proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Upon a redetermination of the borrowing base, either on a periodic or special redetermination date, if borrowings in excess of the revised borrowing capacity were outstanding, the Company could be forced to immediately repay a portion of its debt outstanding under the credit agreement. In October 2017, the borrowing base and aggregate commitments under the facility were reduced to $2.3 billion in connection with the November 1, 2017 regular borrowing base redetermination, and was primarily a result of the sale of the Company's FBIR Assets on September 1, 2017.

A portion of the revolving credit facility in an aggregate amount not to exceed $50 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of September 30, 2017, $41 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until December 2019, when the credit agreement expires and all outstanding borrowings are due. Interest under the revolving credit facility accrues at the Company's option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, the Company incurs commitment fees as set forth in the table below on the unused portion of the aggregate commitments of the lenders under the revolving credit facility, which are included as a component of interest expense.

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At September 30, 2017 and December 31, 2016, the weighted average interest rate on the outstanding principal balance under the credit agreement was 3.2% and 4.0%, respectively.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.50%	2.50%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.75%	2.75%	0.50%
Greater than or equal to 0.90 to 1.0	2.00%	3.00%	0.50%

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. However, the credit agreement permits the Company and certain of its subsidiaries to issue second lien indebtedness of up to $1.0 billion subject to certain conditions and limitations. Except for limited exceptions, the credit agreement also restricts the Company's ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the Company's restricted subsidiaries (as defined in the credit agreement). As of September 30, 2017, there were no retained earnings free from restrictions. The credit agreement requires the Company, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0, (ii) a total senior secured debt to the last four quarters' EBITDAX ratio of less than 3.0 to 1.0 during the Interim Covenant Period (defined below), and thereafter a total debt to EBITDAX ratio of less than 4.0 to 1.0, and (iii) a ratio of the last four quarters' EBITDAX to consolidated cash interest charges of not less than 2.25 to 1.0 during the Interim Covenant Period. Under the credit agreement, the "Interim Covenant Period" is defined as the period from June 30, 2015 until the earlier of (i) April 1, 2018 or (ii) the commencement of an investment-grade debt rating period (as defined in the credit agreement). The Company was in compliance with its covenants under the credit agreement as of September 30, 2017.

The obligations of Whiting Oil and Gas under the credit agreement are collateralized by a first lien on substantially all of Whiting Oil and Gas' and Whiting Resource Corporation's properties. The Company has guaranteed the obligations of Whiting Oil and Gas under the credit agreement and has pledged the stock of its subsidiaries as security for its guarantee.

Senior Notes, Convertible Senior Notes and Senior Subordinated Notes

The following table summarizes the material terms of the Company's senior notes and convertible senior notes outstanding at September 30, 2017.

	2019 Senior Notes	2020 Convertible Senior Notes	2021 Senior Notes	2023 Senior Notes
Outstanding principal (in thousands)	$ 961,409	$ 562,075	$ 873,609	$ 408,296
Interest rate	5.0%	1.25%	5.75%	6.25%
Maturity date	Mar 15, 2019	Apr 1, 2020	Mar 15, 2021	Apr 1, 2023
Interest payment dates	Mar 15, Sep 15	Apr 1, Oct 1	Mar 15, Sep 15	Apr 1, Oct 1
Make-whole redemption date (1)	Dec 15, 2018	N/A (2)	Dec 15, 2020	Jan 1, 2023

(1) On or after these dates, the Company may redeem the applicable series of notes, in whole or in part, at a redemption price equal to 100% of the principal amount redeemed, together with accrued and unpaid interest up to the redemption date. At any time prior to these dates, the Company may redeem the notes at a redemption price that includes an applicable premium as defined in the indentures to such notes.

(2) The indenture governing our 1.25% Convertible Senior Notes due 2020 does not allow for optional redemption by the Company prior to the maturity date.

Senior Notes and Senior Subordinated Notes—In September 2010, the Company issued at par $350 million of 6.5% Senior Subordinated Notes due October 2018 (the “2018 Senior Subordinated Notes”).

In September 2013, the Company issued at par $1.1 billion of 5.0% Senior Notes due March 2019 (the “2019 Senior Notes”) and $800 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400 million of 5.75% Senior Notes due

March 2021 (collectively, the "2021 Senior Notes"). The debt premium recorded in connection with the issuance of the 2021 Senior Notes is being amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.5% per annum.

In March 2015, the Company issued at par $750 million of 6.25% Senior Notes due April 2023 (the "2023 Senior Notes" and together with the 2019 Senior Notes and 2021 Senior Notes, the "Senior Notes").

Exchange of Senior Notes and Senior Subordinated Notes for Convertible Notes. On March 23, 2016, the Company completed the exchange of $477 million aggregate principal amount of Senior Notes and 2018 Senior Subordinated Notes, consisting of (i) $49 million aggregate principal amount of its 2018 Senior Subordinated Notes, (ii) $97 million aggregate principal amount of its 2019 Senior Notes, (iii) $152 million aggregate principal amount of its 2021 Senior Notes, and (iv) $179 million aggregate principal amount of its 2023 Senior Notes, for $477 million aggregate principal amount of convertible senior notes and convertible senior subordinated notes (the "New Convertible Notes"). This exchange transaction was accounted for as an extinguishment of debt for each portion of the Senior Notes and 2018 Senior Subordinated Notes that was exchanged. As a result, Whiting recognized a $91 million gain on extinguishment of debt, which was net of a $4 million non-cash charge for the acceleration of unamortized debt issuance costs and debt premium on the original notes. Each series of New Convertible Notes was recorded at fair value upon issuance, with the difference between the principal amount of the notes and their fair values, totaling $95 million, recorded as a debt discount. The aggregate debt discount of $185 million recorded upon issuance of the New Convertible Notes also included $90 million related to the fair value of the holders' conversion options, which were embedded derivatives that met the criteria to be bifurcated from their host contracts and accounted for separately. Refer to the "Derivative Financial Instruments" and "Fair Value Measurements" footnotes for more information on these embedded derivatives.

During the second quarter of 2016, holders of the New Convertible Notes voluntarily converted all $477 million aggregate principal amount of the New Convertible Notes for approximately 41.8 million shares of the Company's common stock. Upon conversion, the Company paid $46 million in cash consisting of early conversion payments to the holders of the notes, as well as all accrued and unpaid interest on such notes. As a result of the conversions, Whiting recognized a $188 million loss on extinguishment of debt, which consisted of a non-cash charge for the acceleration of unamortized debt issuance costs and debt discount on the notes. As of June 30, 2016, no New Convertible Notes remained outstanding.

Exchange of Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes. On July 1, 2016, the Company completed the exchange of $405 million aggregate principal amount of Senior Notes and 2018 Senior Subordinated Notes for the same aggregate principal amount of new mandatory convertible senior notes and mandatory convertible senior subordinated notes. Refer to "Mandatory Convertible Notes" below for more information on these exchange transactions.

Redemption of 2018 Senior Subordinated Notes. On February 2, 2017, the Company paid $281 million to redeem all of the then outstanding $275 million aggregate principal amount of 2018 Senior Subordinated Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the notes. The Company financed the redemption with borrowings under its credit agreement. As a result of the redemption, Whiting recognized a $2 million loss on extinguishment of debt, which consisted of a non-cash charge for the acceleration of unamortized debt issuance costs on the notes. As of March 31, 2017, no 2018 Senior Subordinated Notes remained outstanding.

2020 Convertible Senior Notes—In March 2015, the Company issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the "2020 Convertible Senior Notes") for net proceeds of $1.2 billion, net of initial purchasers' fees of $25 million. On June 29, 2016, the Company exchanged $129 million aggregate principal amount of its 2020

Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes, and on July 1, 2016, the Company exchanged $559 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Refer to “Mandatory Convertible Notes” below for more information on these exchange transactions.

For the remaining $562 million aggregate principal amount of 2020 Convertible Senior Notes outstanding as of September 30, 2017, the Company has the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company’s intent is to settle the principal amount of the 2020 Convertible Senior Notes in cash upon conversion. Prior to January 1, 2020, the 2020 Convertible Senior Notes will be convertible at the holder’s option only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on June 30, 2015 (and only during such calendar quarter), if the last reported sale price of the Company’s common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the “measurement period”) in which the trading price per $1,000 principal amount of the 2020 Convertible Senior Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of the Company’s common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after January 1, 2020, the 2020 Convertible Senior Notes will be convertible at any time until the second scheduled trading day immediately preceding the April 1, 2020 maturity date of the notes. The notes will be convertible at an initial conversion rate of 25.6410 shares of Whiting's common stock per $1,000 principal amount of the notes, which is equivalent to an initial conversion price of approximately $39.00. The conversion rate will be subject to adjustment in some events. In addition, following certain corporate events that occur prior to the maturity date, the Company will increase, in certain circumstances, the conversion rate for a holder who elects to convert its 2020 Convertible Senior Notes in connection with such corporate event. As of September 30, 2017, none of the contingent conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met.

Upon issuance, the Company separately accounted for the liability and equity components of the 2020 Convertible Senior Notes. The liability component was recorded at the estimated fair value of a similar debt instrument without the conversion feature. The difference between the principal amount of the 2020 Convertible Senior Notes and the estimated fair value of the liability component was recorded as a debt discount and is being amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.6% per annum. The fair value of the 2020 Convertible Senior Notes as of the issuance date was estimated at $1.0 billion, resulting in a debt discount at inception of $238 million. The equity component, representing the value of the conversion option, was computed by deducting the fair value of the liability component from the initial proceeds of the 2020 Convertible Senior Notes issuance. This equity component was recorded, net of deferred taxes and issuance costs, in additional paid-in capital within shareholders' equity, and will not be remeasured as long as it continues to meet the conditions for equity classification.

Transaction costs related to the 2020 Convertible Senior Notes issuance were allocated to the liability and equity components based on their relative fair values. Issuance costs attributable to the liability component were recorded as a reduction to the carrying value of long-term debt on the consolidated balance sheet and are being amortized to interest expense over the term of the notes using the effective interest method. Issuance costs attributable to the equity component were recorded as a charge to additional paid-in capital within shareholders' equity.

The 2020 Convertible Senior Notes consisted of the following at September 30, 2017 and December 31, 2016 (in thousands):

	September 30, 2017	December 31, 2016
Liability component		
Principal	$ 562,075	$ 562,075
Less: unamortized note discount	(57,015)	(72,622)
Less: unamortized debt issuance costs	(4,633)	(5,988)
Net carrying value	$ 500,427	$ 483,465
Equity component (1)	$ 136,522	$ 136,522

(1) Recorded in additional paid-in capital, net of $5 million of issuance costs and $50 million of deferred taxes as of September 30, 2017 and December 31, 2016.

The following table presents the interest expense recognized on the 2020 Convertible Senior Notes related to the stated interest rate and amortization of the debt discount for the three and nine months ended September 30, 2017 and 2016 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Interest expense on 2020 Convertible Senior Notes	$ 7,032	$ 6,745	$ 20,876	$ 36,068

Mandatory Convertible Notes—On June 29, 2016, the Company completed the exchange of $129 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible notes, and on July 1, 2016, the Company completed the exchange of $964 million aggregate principal amount of Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes, consisting of (i) $26 million aggregate principal amount of 2018 Senior Subordinated Notes, (ii) $42 million aggregate principal amount of 2019 Senior Notes, (iii) $559 million aggregate principal amount of 2020 Convertible Senior Notes, (iv) $174 million aggregate principal amount of 2021 Senior Notes, and (v) $163 million aggregate principal amount of 2023 Senior Notes, for the same aggregate principal amount of new mandatory convertible notes (together the “Mandatory Convertible Notes”).

These transactions were accounted for as extinguishments of debt for the portions of Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes that were exchanged. As a result, Whiting recognized a $57 million gain on extinguishment of debt, which was net of a $113 million charge for the non-cash write-off of unamortized debt issuance costs, debt discounts and debt premium on the original notes. In addition, Whiting recorded a $63 million reduction to the equity component of the 2020 Convertible Senior

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Notes, which was net of deferred taxes. The Mandatory Convertible Notes were recorded at fair value upon issuance with the difference between the principal amount of the notes and their fair values, totaling $69 million, recorded as a debt discount. The Mandatory Convertible Notes contained contingent beneficial conversion features, the intrinsic value of which was recognized in additional paid-in capital at the time the contingency was resolved, resulting in an additional debt discount of $233 million. The aggregate debt discount of $302 million was being amortized to interest expense over the term of the notes using the effective interest method.

The July 1, 2016 note exchange transactions triggered an ownership shift as defined under Section 382 of the Internal Revenue Code due to the "deemed share issuance" that resulted from the note exchanges. This triggering event will limit the Company's usage of certain of its net operating losses and tax credits in the future. Refer to the "Income Taxes" footnote for more information.

In July 2016, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 33.2 million shares of the Company's common stock pursuant to the terms of the notes, and the Company paid $3 million in cash consisting of all accrued and unpaid interest on such notes. As a result of the conversions, Whiting recognized a $3 million gain on extinguishment of debt, which was net of a non-cash charge for the acceleration of unamortized debt issuance costs and debt discount on the notes.

In August 2016, the Company completed an induced exchange of $38 million aggregate principal amount of the Mandatory Convertible Notes for approximately 4.9 million shares of the Company's common stock. As a result of the exchange, the Company (i) paid $1 million in cash consisting of all accrued and unpaid interest on such notes, (ii) recognized $4 million of debt inducement expense related to the fair value of the incremental shares issued in the inducement offer over the original conversion terms of the notes, which expense was included in (gain) loss on extinguishment of debt in the condensed consolidated statements of operations, and (iii) recognized a $14 million non-cash charge for the acceleration of unamortized debt discount on the notes, which was included in interest expense in the condensed consolidated statements of operations.

During the fourth quarter of 2016, the remaining $721 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 77.6 million shares of the Company's common stock pursuant to the terms of the notes. As of December 31, 2016, no Mandatory Convertible Notes remained outstanding.

Security and Guarantees

The Senior Notes and the 2020 Convertible Senior Notes are unsecured obligations of Whiting Petroleum Corporation and these unsecured obligations are subordinated to all of the Company's secured indebtedness, which consists of Whiting Oil and Gas' credit agreement.

The Company's obligations under the Senior Notes and the 2020 Convertible Senior Notes are guaranteed by the Company's 100%-owned subsidiaries, Whiting Oil and Gas, Whiting US Holding Company, Whiting Canadian Holding Company ULC and Whiting Resources Corporation (the "Guarantors"). These guarantees are full and unconditional and joint and several among the Guarantors. Any subsidiaries other than these Guarantors are minor subsidiaries as defined by Rule 3-10(h)(6) of Regulation S X of the SEC. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in its consolidated subsidiaries.

5. ASSET RETIREMENT OBLIGATIONS

The Company’s asset retirement obligations represent the present value of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws. The current portions at September 30, 2017 and December 31, 2016 were $5 million and $8 million, respectively, and have been included in accrued liabilities and other in the consolidated balance sheets. The following table provides a reconciliation of the Company’s asset retirement obligations for the nine months ended September 30, 2017 (in thousands):

Asset retirement obligation at January 1, 2017	$	177,004
Additional liability incurred		5,302
Revisions to estimated cash flows (1)		(21,219)
Accretion expense		10,502
Obligations on sold properties		(6,997)
Liabilities settled		(2,777)
Asset retirement obligation at September 30, 2017	$	161,815

(1) Revisions to estimated cash flows during the nine months ended September 30, 2017 are attributable to decreases in the estimates of future costs required to plug and abandon wells in certain fields in the Northern Rocky Mountains.

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6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and it uses derivative instruments to manage its commodity price risk. In addition, the Company periodically enters into contracts that contain embedded features which are required to be bifurcated and accounted for separately as derivatives.

Commodity Derivative Contracts—Historically, prices received for crude oil and natural gas production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and seasonal weather patterns. Whiting enters into derivative contracts such as crude oil costless collars, swaps and sales and delivery contracts to achieve a more predictable cash flow by reducing its exposure to commodity price volatility, thereby ensuring adequate funding for the Company's capital programs and facilitating the management of returns on drilling programs and acquisitions. The Company does not enter into derivative contracts for speculative or trading purposes.

Crude Oil Costless Collars. Costless collars are designed to establish floor and ceiling prices on anticipated future oil or gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements.

The table below details the Company's costless collar derivatives entered into to hedge forecasted crude oil production revenues as of September 30, 2017.

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Three-way collars (1) (2)	Oct - Dec 2017	3,750,000	\$35.00 - \$45.20 - \$58.95
	Jan - Dec 2018	12,600,000	\$36.67 - \$46.67 - \$56.95
Collars	Oct - Dec 2017	750,000	\$53.00 - \$70.44
	Total	17,100,000	

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) Whiting will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

(2) Subsequent to September 30, 2017, the Company entered into additional three-way collar contracts for 2,400,000 Bbl of crude oil volumes for the year ended December 31, 2018.

Crude Oil Sales and Delivery Contract. The Company has a long-term crude oil sales and delivery contract for oil volumes produced from its Redtail field in Colorado. Under the terms of the agreement, Whiting has committed to deliver certain fixed volumes of crude oil through April 2020. The Company determined it was not probable that future oil production from its Redtail field would be sufficient to meet the minimum volume requirements specified in this contract; accordingly, the Company would not settle this contract through physical delivery of crude oil volumes. As a result, Whiting determined that this contract would not qualify for the "normal purchase normal sale" exclusion and has therefore reflected the contract at fair value in the consolidated financial statements. As of September 30, 2017 and December 31, 2016, the estimated fair value of this derivative contract was a liability of $57 million and $9 million, respectively.

Embedded Derivatives—In March 2016, the Company issued convertible notes that contained debtholder conversion options which the Company determined were not clearly and closely related to the debt host contracts, and the Company therefore bifurcated these embedded features and reflected them at fair value in the consolidated financial statements. During the second quarter of 2016, the entire aggregate principal amount of these notes was converted into shares of the Company's common stock, and the fair value of these embedded derivatives as of September 30, 2017 and December 31, 2016 was therefore zero.

In July 2016, the Company entered into a purchase and sale agreement with the buyer of its North Ward Estes Properties, whereby the buyer agreed to pay Whiting additional proceeds of $100,000 for every $0.01 that, as of June 28, 2018, the average NYMEX crude oil futures contract price for each month from August 2018 through July 2021 is above $50.00/Bbl up to a maximum amount of $100 million. The Company determined that this NYMEX-linked contingent payment was not clearly and closely related to the host contract, and the Company therefore bifurcated this embedded feature and reflected it at its estimated fair value of $51 million in the consolidated financial statements as of December 31, 2016. On July 19, 2017, however, the buyer paid $35 million to Whiting to settle this NYMEX-linked contingent payment, and accordingly, the embedded derivative's fair value was zero as of September 30, 2017.

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Derivative Instrument Reporting—All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the “normal purchase normal sale” exclusion or other derivative scope exceptions. The following tables summarize the effects of derivative instruments on the consolidated statements of operations for the three and nine months ended September 30, 2017 and 2016 (in thousands):

Not Designated as ASC 815 Hedges	Statement of Operations Classification	(Gain) Loss Recognized in Income Nine Months Ended September 30, 2017	2016
Commodity contracts	Derivative (gain) loss, net	$ 28,572	$ 27,663
Embedded derivatives	Derivative (gain) loss, net	18,709	(56,095)
Total		$ 47,281	$ (28,432)

Not Designated as ASC 815 Hedges	Statement of Operations Classification	(Gain) Loss Recognized in Income Three Months Ended September 30, 2017	2016
Commodity contracts	Derivative (gain) loss, net	$ 30,867	$ (22,302)
Embedded derivatives	Derivative (gain) loss, net	-	(8,130)
Total		$ 30,867	$ (30,432)

Offsetting of Derivative Assets and Liabilities. The Company nets its financial derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The following tables summarize the location and fair value amounts of all the Company’s derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets (in thousands):

	September 30, 2017 (1)		
Not Designated as	Gross Recognized Assets/	Gross Amounts	Net Recognized Fair Value Assets/

ASC 815 Hedges	Balance Sheet Classification	Liabilities	Offset	Liabilities
Derivative assets				
Commodity contracts - current	Prepaid expenses and other	$ 25,150	$ (24,577)	$ 573
Commodity contracts - non-current	Other long-term assets	10,810	(10,810)	-
Total derivative assets		$ 35,960	$ (35,387)	$ 573
Derivative liabilities				
Commodity contracts - current	Derivative liabilities	$ 49,722	$ (24,577)	$ 25,145
Commodity contracts - non-current	Other long-term liabilities	45,571	(10,810)	34,761
Total derivative liabilities		$ 95,293	$ (35,387)	$ 59,906

		December 31, 2016 (1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets				
Commodity contracts - current	Prepaid expenses and other	$ 21,405	$ (21,405)	$ -
Commodity contracts - non-current	Other long-term assets	9,495	(9,495)	-
Embedded derivatives - non-current	Other long-term assets	50,632	-	50,632
Total derivative assets		$ 81,532	$ (30,900)	$ 50,632
Derivative liabilities				
Commodity contracts - current	Derivative liabilities	$ 39,033	$ (21,405)	$ 17,628
Commodity contracts - non-current	Other long-term liabilities	19,724	(9,495)	10,229
Total derivative liabilities		$ 58,757	$ (30,900)	$ 27,857

(1) Because counterparties to the Company's financial derivative contracts subject to master netting arrangements are lenders under Whiting Oil and Gas' credit agreement, which eliminates its need to post or receive collateral associated with its derivative positions, columns for cash collateral pledged or received have not been presented in these tables.

Contingent Features in Financial Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's financial derivative contracts are high credit-quality financial institutions that are lenders under Whiting's credit agreement. The Company uses only credit agreement participants to hedge with, since these institutions are secured equally with the holders of Whiting's bank debt, which eliminates the potential need to post collateral when Whiting is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

7. FAIR VALUE MEASUREMENTS

The Company follows FASB ASC Topic 820, Fair Value Measurement and Disclosure, which establishes 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: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company reflects transfers between the three levels at the beginning of the reporting period in which the availability of observable inputs no longer justifies classification in the original level.

Cash, cash equivalents, restricted cash, accounts receivable and accounts payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The Company's credit agreement has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates and the applicable margins represent market rates.

The Company's senior notes and senior subordinated notes are recorded at cost, and the Company's convertible senior notes are recorded at fair value at the date of issuance. The following table summarizes the fair values and carrying values of these instruments as of September 30, 2017 and December 31, 2016 (in thousands):

	September 30, 2017		December 31, 2016	
	Fair Value (1)	Carrying Value (2)	Fair Value (1)	Carrying Value (2)
6.5% Senior Subordinated Notes due 2018	$ -	$ -	$ 275,121	$ 273,506
5.0% Senior Notes due 2019	961,409	958,176	961,409	956,607
1.25% Convertible Senior Notes due 2020	500,598	500,427	503,057	483,465
5.75% Senior Notes due 2021	860,505	869,073	868,149	868,460
6.25% Senior Notes due 2023	397,578	403,767	408,296	403,265
Total	$ 2,720,090	$ 2,731,443	$ 3,016,032	$ 2,985,303

(1) Fair values are based on quoted market prices for these debt securities, and such fair values are therefore designated as Level 1 within the valuation hierarchy.
(2) Carrying values are presented net of unamortized debt issuance costs and debt discounts or premiums.

The Company’s derivative financial instruments are recorded at fair value and include a measure of the Company’s own nonperformance risk or that of its counterparty, as appropriate. The following tables present information about the Company’s financial assets and

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liabilities measured at fair value on a recurring basis as of September 30, 2017 and December 31, 2016, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value September 30, 2017
Financial Assets				
Commodity derivatives – current	$ -	$ 573	$ -	$ 573
Total financial assets	$ -	$ 573	$ -	$ 573
Financial Liabilities				
Commodity derivatives – current	$ -	$ 1,762	$ 23,383	$ 25,145
Commodity derivatives – non-current	-	1,370	33,391	34,761
Total financial liabilities	$ -	$ 3,132	$ 56,774	$ 59,906

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2016
Financial Assets				
Embedded derivatives – non-current	$ -	$ 50,632	$ -	$ 50,632
Total financial assets	$ -	$ 50,632	$ -	$ 50,632
Financial Liabilities				
Commodity derivatives – current	$ -	$ 14,664	$ 2,964	$ 17,628
Commodity derivatives – non-current	-	3,979	6,250	10,229
Total financial liabilities	$ -	$ 18,643	$ 9,214	$ 27,857

The following methods and assumptions were used to estimate the fair values of the Company's financial assets and liabilities that are measured on a recurring basis:

Commodity Derivatives. Commodity derivative instruments consist mainly of costless collars for crude oil. The Company's costless collars are valued based on an income approach. The option model considers various assumptions, such as quoted forward prices for commodities, time value and volatility factors. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The discount rates used in the fair values of these instruments include a measure of either the Company's or the counterparty's nonperformance risk, as appropriate. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

In addition, the Company has a long-term crude oil sales and delivery contract, whereby it has committed to deliver certain fixed volumes of crude oil through April 2020. Whiting has determined that the contract does not meet the "normal purchase normal sale" exclusion, and has therefore reflected this contract at fair value in its consolidated financial statements. This commodity derivative was valued based on a probability-weighted income approach which considers various assumptions, including quoted spot prices for commodities, market differentials for crude oil, U.S. Treasury rates and either the Company's or the counterparty's nonperformance risk, as appropriate. The assumptions used in the valuation of the crude oil sales and delivery contract include certain market differential metrics that were unobservable during the term of the contract. Such unobservable inputs were significant to the contract valuation methodology, and the contract's fair value was therefore designated as Level 3 within the valuation hierarchy.

Embedded Derivatives. The Company had embedded derivatives related to its convertible notes that were issued in March 2016. The notes contained debtholder conversion options which the Company determined were not clearly and closely related to the debt host contracts and the Company therefore bifurcated these embedded features and reflected them at fair value in the consolidated financial statements. Prior to their settlements, the fair values of these embedded derivatives were determined using a binomial lattice model which considered various inputs including (i) Whiting's common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) recovery rates in the event of default, (iv) default intensity, and (v) volatility of Whiting's common stock. The expected volatility and default intensity used in the valuation were unobservable in the marketplace and significant to the valuation methodology, and the embedded derivatives' fair value was therefore designated as Level 3 in the valuation hierarchy. During the second quarter of 2016, the entire aggregate principal amount of these convertible notes was converted into shares of the Company's common stock. Accordingly, the embedded derivatives were settled in their entirety as of June 30, 2016.

The Company had an embedded derivative related to its purchase and sale agreement with the buyer of the North Ward Estes Properties. The agreement included a Contingent Payment linked to NYMEX crude oil prices which the Company determined was not clearly and closely related to the host contract, and the Company therefore bifurcated this embedded feature and reflected it at fair value in the consolidated financial statements prior to settlement. The fair value of this embedded derivative was determined using a modified

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Black-Scholes swaption pricing model which considers various assumptions, including quoted forward prices for commodities, time value and volatility factors. These assumptions were observable in the marketplace throughout the full term of the financial instrument, could be derived from observable data or were supported by observable levels at which transactions are executed in the marketplace, and were therefore designated as Level 2 within the valuation hierarchy. The discount rate used in the fair value of this instrument included a measure of the counterparty's nonperformance risk. On July 19, 2017, the buyer paid $35 million to Whiting in satisfaction of this Contingent Payment. Accordingly, the embedded derivative was settled in its entirety as of that date.

Level 3 Fair Value Measurements—A third-party valuation specialist is utilized to determine the fair value of the Company's derivative instruments designated as Level 3. The Company reviews these valuations, including the related model inputs and assumptions, and analyzes changes in fair value measurements between periods. The Company corroborates such inputs, calculations and fair value changes using various methodologies, and reviews unobservable inputs for reasonableness utilizing relevant information from other published sources.

The following table presents a reconciliation of changes in the fair value of financial assets or liabilities designated as Level 3 in the valuation hierarchy for the three and nine months ended September 30, 2017 and 2016 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Fair value liability, beginning of period	$ (61,952)	$ (9,884)	$ (9,214)	$ (4,027)
Recognition of embedded derivatives associated with convertible note issuances	-	-	-	(89,884)
Unrealized gains on embedded derivatives included in earnings (1)	-	-	-	47,965
Settlement of embedded derivatives upon conversion of convertible notes	-	-	-	41,919
Unrealized gains (losses) on commodity derivative contracts included in earnings (1)	5,178	288	(47,560)	(5,569)
Transfers into (out of) Level 3	-	-	-	-
Fair value liability, end of period	$ (56,774)	$ (9,596)	$ (56,774)	$ (9,596)

(1) Included in derivative (gain) loss, net in the consolidated statements of operations.

Quantitative Information about Level 3 Fair Value Measurements. The significant unobservable inputs used in the fair value measurement of the Company's commodity derivative instrument designated as Level 3 are as follows:

Derivative Instrument	Valuation Technique	Unobservable Input	Amount
Commodity derivative contract	Probability-weighted income approach	Market differential for crude oil	$3.93 - $4.83 per

Bbl

Sensitivity to Changes in Significant Unobservable Inputs. As presented above, the significant unobservable inputs used in the fair value measurement of Whiting's commodity derivative contract are the market differentials for crude oil over the term of the contract. Significant increases or decreases in these unobservable inputs in isolation would result in a significantly lower or higher, respectively, fair value liability measurement.

Non-recurring Fair Value Measurements—The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company did not recognize any impairment write-downs with respect to its proved property during the 2017 or 2016 reporting periods presented.

8. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

Common Stock—In September 2017, the Company announced plans to effect a reverse stock split of Whiting's common stock at a ratio ranging from any whole number between one-for-two to one-for-six, as determined by the Company's Board of Directors, and a reduction in the number of authorized shares of Whiting's common stock as set forth in the chart below based on the reverse stock split ratio selected.

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Ratio	Number of Shares of Common Stock Authorized
1:2	450,000,000
1:3	300,000,000
1:4	225,000,000
1:5	180,000,000
1:6	150,000,000

The Company will hold a special meeting of stockholders on November 8, 2017 to seek approval for the reverse stock split and authorized share reduction.

Noncontrolling Interest—The Company's noncontrolling interest represented an unrelated third party's 25% ownership interest in Sustainable Water Resources, LLC ("SWR"). During the third quarter of 2017, the third party's ownership interest in SWR was assigned back to SWR. The table below summarizes the activity for the equity attributable to the noncontrolling interest (in thousands):

	Nine Months Ended September 30,	
	2017	2016
Balance at beginning of period	$ 7,962	$ 7,984
Net loss	(14)	(18)
Conveyance of ownership interest	(7,948)	-
Balance at end of period	$ -	$ 7,966

9. STOCK-BASED COMPENSATION

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2013 Equity Incentive Plan (the "2013 Equity Plan"), which replaced the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the "2003 Equity Plan") and includes the authority to issue 10,800,000 shares of the Company's common stock. Upon shareholder approval of the 2013 Equity Plan, the 2003 Equity Plan was terminated. The 2003 Equity Plan continues to govern awards that were outstanding as of the date of its termination, which remain in effect pursuant to their terms. Any shares netted or forfeited under the 2003 Equity Plan and any shares forfeited under the 2013 Equity Plan will be available for future issuance under the 2013 Equity Plan. However, shares netted for tax withholding under the 2013 Equity Plan will be cancelled and will not be available for future issuance. On December 8, 2014, in conjunction with the acquisition of Kodiak, the Company increased the number of shares issuable under the 2013 Equity Plan by 978,161 shares to accommodate for the conversion of Kodiak's outstanding equity awards to Whiting equity awards upon closing of the acquisition. Any shares netted or forfeited under this increased availability will be cancelled and will not be available for future issuance under the 2013 Equity Plan. Under the 2013 Equity Plan, no employee or officer participant may be granted options for more than 900,000 shares of common stock, stock appreciation rights relating to more than 900,000 shares of common stock, more than 600,000 shares of restricted stock, more than 600,000 restricted stock units, more than 600,000 performance shares, or more than 600,000 performance units during any calendar year. In addition, no non-employee director participant may be granted options for more than 100,000 shares of common stock, stock appreciation rights relating to more than 100,000 shares of common stock, more than 100,000 shares of restricted stock, or more than 100,000 restricted stock units during any calendar year. As of September 30, 2017, 5,084,490 shares of common stock remained available for grant under the 2013 Equity Plan.

Restricted Stock and Performance Shares—The Company grants service-based restricted stock awards to executive officers and employees, which generally vest ratably over a three-year service period, and to directors, which generally vest over a one-year service period. In addition, the Company grants performance share awards to executive officers that are subject to market-based vesting criteria as well as a three-year service period. Upon adoption of ASU 2016-09 on January 1, 2017, the Company elected to account for forfeitures of awards granted under these plans as they occur in determining compensation expense. The Company recognizes compensation expense for all awards subject to market-based vesting conditions regardless of whether it becomes probable that these conditions will be achieved or not, and compensation expense is not reversed if vesting does not actually occur.

During the nine months ended September 30, 2017 and 2016, 1,637,462 and 2,952,193 shares, respectively, of service-based restricted stock were granted to employees, executive officers and directors under the 2013 Equity Plan. The grant date fair value of restricted stock is determined based on the closing bid price of the Company's common stock on the grant date. The weighted average grant date fair value of restricted stock was $11.38 per share and $6.95 per share for the nine months ended September 30, 2017 and 2016, respectively.

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In January 2017 and 2016, 633,479 and 1,073,143 performance shares, respectively, subject to certain market-based vesting criteria were granted to executive officers under the 2013 Equity Plan. These market-based awards cliff vest on the third anniversary of the grant date, and the number of shares that will vest at the end of that three-year performance period is determined based on the rank of Whiting's cumulative stockholder return compared to the stockholder return of a peer group of companies over the same three-year period. The number of shares earned could range from zero up to two times the number of shares initially granted.

For awards subject to market conditions, the grant date fair value is estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility is calculated based on the historical volatility of Whiting's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing these market-based awards were as follows:

	2017	2016
Number of simulations	2,500,000	2,500,000
Expected volatility	82.44%	60.8%
Risk-free interest rate	1.52%	1.13%
Dividend yield	-	-

The grant date fair value of the market-based awards as determined by the Monte Carlo valuation model was $16.36 per share and $6.39 per share in January 2017 and 2016, respectively.

The following table shows a summary of the Company's restricted stock and performance share activity for the nine months ended September 30, 2017:

	Number of Shares		Weighted Average Grant Date Fair Value
	Service-Based Restricted Stock	Market-Based Performance Shares	
Nonvested awards, January 1, 2017	3,067,804	2,092,810	$ 13.55
Granted	1,637,462	633,479	12.77
Vested	(1,182,970)	-	13.00
Forfeited	(245,732)	(776,525)	20.74

Nonvested awards, September 30, 2017	3,276,564	1,949,764	$ 11.93

Stock Options—There was no significant stock option activity during the nine months ended September 30, 2017 and 2016.

Total stock compensation expense recognized for restricted shares and stock options was $6 million for each of the three months ended September 30, 2017 and 2016, and $19 million and $20 million for the nine months ended September 30, 2017 and 2016, respectively.

10. INCOME TAXES

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The provision for income taxes for the three and nine months ended September 30, 2017 and 2016 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% to pre-tax income primarily because of state income taxes and estimated permanent differences. In addition, during the third quarter of 2016, the Company's note exchange transactions triggered an ownership shift within the meaning of Section 382 of the Internal Revenue Code due to the "deemed share issuance" that resulted from the note exchanges. The ownership shift will limit Whiting's usage of certain of its net operating losses and tax credits in the future, and as a result, the Company recognized a non-cash charge of $454 million during the third quarter of 2016.

The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgment including, but not limited to, the expected operating income for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent and temporary differences, and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, additional information becomes known or as the tax environment changes.

Upon adoption of ASU 2016-09 on January 1, 2017, the Company recorded $70 million of previously unrecognized excess tax benefits related to stock-based compensation, for which a full valuation allowance was also recognized.

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11. EARNINGS PER SHARE

The reconciliations between basic and diluted loss per share are as follows (in thousands, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Basic Loss Per Share				
Net loss attributable to common shareholders	$ (286,432)	$ (693,052)	$ (439,370)	$ (1,165,841)
Weighted average shares outstanding	362,794	280,418	362,713	237,100
Loss per common share	$ (0.79)	$ (2.47)	$ (1.21)	$ (4.92)
Diluted Loss Per Share				
Adjusted net loss attributable to common shareholders	$ (286,432)	$ (693,052)	$ (439,370)	$ (1,165,841)
Weighted average shares outstanding	362,794	280,418	362,713	237,100
Loss per common share	$ (0.79)	$ (2.47)	$ (1.21)	$ (4.92)

During the three months ended September 30, 2017, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 242,748 shares of service-based restricted stock and 3,513 stock options. In addition, the diluted earnings per share calculation for the three months ended September 30, 2017 excludes the effect of 3,553,915 common shares for stock options that were out-of-the-money and 889,354 shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2017.

During the three months ended September 30, 2016, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of (i) 81,549,680 shares issuable for convertible notes prior to their conversions under the if-converted method, (ii) 1,240,145 shares of service-based restricted stock, and (iii) 4,448 stock options. In addition, the diluted earnings per share calculation for the three months ended September 30, 2016 excludes the effect of 2,090,383 common shares for stock options that were out-of-the-money and 897,005 shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2016.

During the nine months ended September 30, 2017, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 1,881,532 shares of service-based restricted stock and 4,435 stock options. In addition, the diluted earnings per share calculation for the nine months ended September 30, 2017 excludes the effect of 2,079,183 common shares for stock options that were out-of-the-money and 563,739 shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2017.

During the nine months ended September 30, 2016, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of (i) 35,560,679 shares issuable for convertible notes prior to their conversions under the if-converted method, (ii) 1,351,434 shares of service-based restricted stock, and (iii) 4,573 stock options. In addition, the diluted earnings per share calculation for the nine months ended September 30, 2016 excludes the effect of 2,065,797 common shares for stock options that were out-of-the-money and 523,351 shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2016.

Refer to the “Stock-Based Compensation” footnote for further information on the Company’s restricted stock and stock options.

As discussed in the “Long-Term Debt” footnote, the Company has the option to settle the 2020 Convertible Senior Notes with cash, shares of common stock or any combination thereof upon conversion. Based on the initial conversion price, the entire outstanding principal amount of the 2020 Convertible Senior Notes as of September 30, 2017 would be convertible into approximately 14.4 million shares of the Company’s common stock. However, the Company’s intent is to settle the principal amount of the notes in cash upon conversion. As a result, only the amount by which the conversion value exceeds the aggregate principal amount of the notes (the “conversion spread”) is considered in the diluted earnings per share computation under the treasury stock method. As of September 30, 2017 and 2016, the conversion value did not exceed the principal amount of the notes. Accordingly, there was no impact to diluted earnings per share or the related disclosures for those periods.

12. COMMITMENTS AND CONTINGENCIES

Upon completion of the Dakota Access Pipeline on June 1, 2017, the Company’s physical delivery contract for the delivery of fixed volumes of crude oil from Whiting’s Sanish field in Mountrail County, North Dakota became effective. Under the terms of the agreement, Whiting has committed to deliver 15 MBbl/d for a term of seven years, or pay a deficiency fee equal to $7.00 per undelivered

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Bbl. The Company believes its production and reserves are sufficient to fulfill this delivery commitment, and therefore expects to avoid any payments for deficiencies under this contract.

Additionally, the Company has two physical delivery contracts tied to crude oil production at Whiting's Redtail field in Weld County, Colorado. As of September 30, 2017, these two contracts had remaining delivery commitments of 5.1 MMBbl of crude oil for the remainder of 2017 and 21.5 MMBbl, 23.3 MMBbl and 6.6 MMBbl of crude oil for the years ended December 31, 2018 through 2020, respectively. The Company has determined that it is not probable that future oil production from its Redtail field will be sufficient to meet the minimum volume requirements specified in these physical delivery contracts, and as a result, the Company expects to make periodic deficiency payments for any shortfalls in delivering the minimum committed volumes. During the three and nine months ended September 30, 2017, total deficiency payments under these contracts amounted to $17 million and $52 million, respectively. The Company recognizes any monthly deficiency payments in the period in which the underdelivery takes place and the related liability has been incurred.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Unless the context otherwise requires, the terms "Whiting", "we", "us", "our" or "ours" when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), Whiting US Holding Company, Whiting Canadian Holding Company ULC (formerly Kodiak Oil & Gas Corp., "Kodiak"), Whiting Resources Corporation and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in development, production, acquisition and exploration activities primarily in the Rocky Mountains region of the United States. Our current operations and capital programs are focused on organic drilling opportunities and on the development of previously acquired properties, specifically on projects that we believe provide the greatest potential for repeatable success and production growth, while selectively pursuing acquisitions that complement our existing core properties. As a result of lower crude oil prices during 2015 and 2016, we significantly reduced our level of capital spending and focused our drilling activity on projects that provide the highest rate of return. During 2017, we shifted our focus to adding production and reserves through the strategic deployment of capital at our Williston Basin properties and Redtail field, while more closely aligning our capital spending with cash flows generated from operations. In addition, we continually evaluate our property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own, such as the asset sales discussed below under "Acquisition and Divestiture Highlights" and in the "Acquisitions and Divestitures" footnote in the notes to condensed consolidated financial statements.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as oil and gas prices, economic, political and regulatory developments, competition from other sources of energy, and the other items discussed under the caption "Risk Factors" in Item 1A of our Annual Report on Form 10-K for the period ended December 31, 2016. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas prices since the first quarter of 2015:

	2015				2016				2017		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Crude oil	$ 48.57	$ 57.96	$ 46.44	$ 42.17	$ 33.51	$ 45.60	$ 44.94	$ 49.33	$ 51.86	$ 48.29	$ 48.19
Natural gas	$ 2.99	$ 2.61	$ 2.74	$ 2.17	$ 2.06	$ 1.98	$ 2.93	$ 2.98	$ 3.07	$ 3.09	$ 2.89

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and gas reserve quantities. Substantial and extended declines in oil, NGL and natural gas prices may result in impairments of our proved oil and gas properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. In addition, lower commodity prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of our lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under our credit agreement. Alternatively, higher oil prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives.

2017 Highlights and Future Considerations

Operational Highlights

Northern Rocky Mountains – Williston Basin

Our properties in the Williston Basin of North Dakota and Montana target the Bakken and Three Forks formations. Net production from the Williston Basin averaged 102.0 MBOE/d for the third quarter of 2017, representing a 3% decrease from 105.5 MBOE/d in the second quarter of 2017. Across our acreage in the Williston Basin, we have implemented new completion designs which utilize cemented liners, plug-and-perf technology, significantly higher sand volumes, new diversion technology and both hybrid and slickwater fracture stimulation methods, which have resulted in improved initial production rates. As of September 30, 2017, we had four rigs active in the Williston Basin, and we plan to continue to operate four rigs in this area for the remainder of the year. We anticipate having an inventory of approximately 50 drilled uncompleted wells in this area at the end of 2017.

Central Rocky Mountains – Denver Julesburg Basin

Our Redtail field in the Denver Julesburg Basin (“DJ Basin”) in Weld County, Colorado targets the Niobrara and Codell/Fort Hays formations. Net production from the Redtail field averaged 11.8 MBOE/d in the third quarter of 2017, representing a 78% increase from 6.6 MBOE/d in the second quarter of 2017. We have established production in the Niobrara “A”, “B” and “C” zones and the Codell/Fort Hays formations. We have implemented a new wellbore configuration in this area, which significantly reduces drilling times. In response to low commodity prices, we suspended completion operations in this area beginning in the second quarter of 2016, however, we resumed completion activity during the first quarter of 2017 and added a second completion crew in April. During the third quarter of 2017, we completed and brought on production a significant portion of our drilled uncompleted well inventory from yearend 2016, and we anticipate having an inventory of approximately 39 drilled uncompleted wells in this area at the end of 2017.

Our Redtail gas plant processes the associated gas produced from our wells in this area, and has a current inlet capacity of 50 MMcf/d. As of September 30, 2017, the plant was processing over 17 MMcf/d.

Financing Highlights

On February 2, 2017, we paid $281 million to redeem all of the remaining $275 million aggregate principal amount of our 2018 Senior Subordinated Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the notes. We financed the redemption with borrowings under our credit agreement. Refer to the “Long-Term Debt” footnote in the notes to condensed consolidated financial statements for more information on this financing transaction.

On September 7, 2017, we announced our plans to effect a reverse stock split of our common stock at a ratio ranging from any whole number between one-for-two to one-for-six, as determined by our Board of Directors, and a reduction in the number of authorized shares of our common stock based on the reverse stock split ratio selected. There will be a special meeting of stockholders on November 8, 2017 to seek approval for the reverse stock split and authorized share reduction. Refer to the “Shareholders’ Equity and Noncontrolling Interest” footnote in the notes to condensed consolidated financial statements for more information.

In October 2017, the borrowing base and aggregate commitments under our credit agreement were reduced from $2.5 billion to $2.3 billion in connection with the November 1, 2017 regular borrowing base redetermination, and was primarily the result of the sale of our Fort Berthold Indian Reservation area assets on September 1, 2017, as discussed below under “Acquisition and Divestiture Highlights”. All other terms of the credit agreement remain unchanged.

Acquisition and Divestiture Highlights

On January 1, 2017, we completed the sale of our 50% interest in the Robinson Lake gas processing plant located in Mountrail County, North Dakota and our 50% interest in the Belfield gas processing plant located in Stark County, North Dakota, as well as the associated natural gas, crude oil and water gathering systems, effective January 1, 2017, for aggregate sales proceeds of $375 million (before closing adjustments). We used the net proceeds from this transaction to repay a portion of the debt outstanding under our credit agreement.

On July 19, 2017, the buyer of our North Ward Estes properties paid us $35 million to settle a contingent payment associated with the original purchase and sale agreement, which sale closed in July 2016. This settlement resulted in a pre-tax gain of $3 million. Refer to the “Acquisitions and Divestitures” footnote in the notes to condensed consolidated financial statements for more information on this transaction.

On September 1, 2017, we completed the sale of our interests in certain producing oil and gas properties located in the Fort Berthold Indian Reservation area in Dunn and McLean counties of North Dakota, as well as other related assets and liabilities, (the “FBIR Assets”) for aggregate sales proceeds of $500 million (before closing adjustments). The sale was effective September 1, 2017 and resulted in a pre-tax loss on sale of $402 million. We used the net proceeds from the sale to repay a portion of the debt outstanding under our credit agreement. The properties spanned approximately 29,600 net developed acres and consisted of estimated proved reserves of 32 MMBOE as of December 31, 2016, representing 5% of our proved reserves as of that date. The FBIR Assets generated 7% (or 8.3 MBOE/d) of our August 2017 average daily production.

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Results of Operations

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

	Nine Months Ended September 30,	
	2017	2016
Net production		
Oil (MMBbl)	21.3	26.4
NGLs (MMBbl)	5.0	5.0
Natural gas (Bcf)	30.2	31.2
Total production (MMBOE)	31.3	36.6
Net sales (in millions)		
Oil (1)	$ 887.1	$ 864.6
NGLs	67.1	38.5
Natural gas	52.8	39.2
Total oil, NGL and natural gas sales	$ 1,007.0	$ 942.3
Average sales prices		
Oil (per Bbl) (1)	$ 41.73	$ 32.70
Effect of oil hedges on average price (per Bbl)	0.50	4.93
Oil net of hedging (per Bbl)	$ 42.23	$ 37.63
Weighted average NYMEX price (per Bbl) (2)	$ 49.51	$ 40.84
NGLs (per Bbl)	$ 13.33	$ 7.78
Natural gas (per Mcf)	$ 1.75	$ 1.25
Weighted average NYMEX price (per MMBtu) (2)	$ 3.01	$ 2.30
Costs and expenses (per BOE)		
Lease operating expenses	$ 8.53	$ 8.40
Production taxes	$ 2.76	$ 2.16
Depreciation, depletion and amortization	$ 21.49	$ 24.61
General and administrative	$ 2.96	$ 3.07

(1) Before consideration of hedging transactions.

(2) Average NYMEX pricing weighted for monthly production volumes.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $65 million to $1.0 billion when comparing the first nine months of 2017 to the same period in 2016. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil and natural gas sales volumes decreased 20% and 3%, respectively, while our NGL sales volumes remained consistent between periods. The oil volume decrease between periods was primarily attributable to normal field production decline across several of our areas resulting from reduced drilling and completion activity during 2016 and the first nine months of 2017 in response to the depressed commodity price environment. In addition, we completed certain oil and gas property divestitures during 2016 and 2017, which negatively impacted oil production in the first nine months of 2017 by 1,775 MBbl. These decreases were partially offset by new wells drilled and completed in the Williston Basin and DJ Basin which added 4,475 MBbl and 565 MBbl, respectively, of oil production during the first nine months of 2017 as compared to the first nine months of 2016. The gas volume decrease between periods was primarily due to normal field production decline across several of our areas, as well as 2016 and 2017 property divestitures which negatively impacted gas production in the first nine months of 2017 by 550 MMcf. These decreases were partially offset by new wells drilled and completed at our Williston Basin and DJ Basin properties which resulted in 6,610 MMcf and 330 MMcf, respectively, of additional gas volumes during the first nine months of 2017 as compared to the first nine months of 2016.

These overall production-related decreases in net revenue were offset by increases in the average sales price realized for oil, NGLs and natural gas in the first nine months of 2017 compared to 2016. Our average price for oil (before the effects of hedging), NGLs and natural gas increased 28%, 71% and 40%, respectively, between periods. Our average sales price realized for oil is impacted by deficiency payments we are making under two physical delivery contracts at our Redtail field due to our inability to meet the minimum volume commitments under these contracts. During the nine months ended September 30, 2017 and 2016, our total average sales price realized for oil was $2.46 per Bbl lower and $1.12 per Bbl lower, respectively, as a result of these deficiency payments. These

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agreements will continue to negatively impact the price we receive for oil from our Redtail field through April 2020, when the contracts terminate. Refer to the "Commitments and Contingencies" footnote in the notes to condensed consolidated financial statements for more information on these physical delivery contracts and the related deficiency payments.

Lease Operating Expenses. Our lease operating expenses ("LOE") during the first nine months of 2017 were $267 million, a $40 million decrease over the same period in 2016. This decrease was primarily due to a decline in the costs of oilfield goods and services resulting from the general downturn in the oil and gas industry, as well as cost reduction measures we have implemented and the elimination of $14 million of LOE attributable to properties that we divested during 2016 and the first nine months of 2017.

Our lease operating expenses on a BOE basis, however, increased when comparing the first nine months of 2017 to the same 2016 period. LOE per BOE amounted to $8.53 during the first nine months of 2017, which represents an increase of $0.13 per BOE (or 2%) from the first nine months of 2016. This increase was mainly due to lower overall production volumes between periods, partially offset by the overall decrease in LOE expense discussed above.

Production Taxes. Our production taxes during the first nine months of 2017 were $87 million, a $7 million increase over the same period in 2016, which increase was primarily due to higher oil, NGL and natural gas sales between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis remained relatively consistent at 8.6% and 8.4% for the first nine months of 2017 and 2016, respectively.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense decreased $228 million in 2017 as compared to the first nine months of 2016. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2017	2016
Depletion	$ 657,152	$ 884,017
Depreciation	5,634	6,348
Accretion of asset retirement obligations	10,502	10,512
Total	$ 673,288	$ 900,877

DD&A decreased between periods due to $227 million in lower depletion expense, consisting of a $117 million decrease related to a lower depletion rate between periods and a $110 million decrease due to lower overall production volumes during the first nine months of 2017. On a BOE basis, our overall DD&A rate of $21.49 for the first nine months of 2017 was 13% lower than the rate of $24.61 for the same period in 2016. The primary factors contributing to this lower DD&A rate were (i) an increase to proved and proved developed reserves over the last twelve months (excluding the effect of divestitures) mainly due to higher average oil and natural gas prices used to calculate our reserves, as well as upward performance revisions, extensions and discoveries in our Williston Basin area, and (ii) the impact of property divestitures over the past twelve months. These factors that positively impacted our DD&A rate were partially offset by $721 million in drilling and development expenditures over the past twelve months.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $22 million for the first nine months of 2017 as compared to the same period in 2016. The components of our exploration and impairment expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2017	2016
Exploration	$ 19,523	$ 39,659
Impairment	44,270	45,906
Total	$ 63,793	$ 85,565

Exploration costs decreased $20 million during the first nine months of 2017 as compared to the same period in 2016 primarily due to $18 million of lower rig termination fees incurred between periods.

Impairment expense for the first nine months of 2017 and 2016 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties.

General and Administrative Expenses. We report general and administrative ("G&A") expenses net of third-party reimbursements and internal allocations. The components of our G&A expenses were as follows (in thousands):

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	Nine Months Ended September 30,	
	2017	2016
General and administrative expenses	$ 170,884	$ 203,454
Reimbursements and allocations	(78,240)	(91,227)
General and administrative expenses, net	$ 92,644	$ 112,227

G&A expense before reimbursements and allocations decreased $33 million during the first nine months of 2017 as compared to the same period in 2016 primarily due to lower employee compensation. Employee compensation decreased $31 million for the first nine months of 2017 as compared to the same period in 2016 primarily due to reductions in personnel over the past twelve months. The decrease in reimbursements and allocations for the first nine months of 2017 was the result of a lower number of field workers on Whiting-operated properties associated with reduced drilling activity, as well as property divestitures over the past twelve months.

Our general and administrative expenses on a BOE basis also decreased when comparing the first nine months of 2017 to the same 2016 period. G&A expense per BOE amounted to $2.96 during the first nine months of 2017, which represents a decrease of $0.11 per BOE (or 4%) from the first nine months of 2016. This decrease was mainly due to lower employee compensation, partially offset by lower overall production volumes between periods.

Derivative (Gain) Loss, Net. Our commodity derivative contracts and embedded derivatives are marked to market each quarter with fair value gains and losses recognized immediately in earnings as derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment to or from the counterparty. Derivative (gain) loss, net amounted to a loss of $47 million for the nine months ended September 30, 2017, which consisted of a $48 million fair value loss on our long-term crude oil sales and delivery contract and a $19 million fair value loss on embedded derivatives, partially offset by a $20 million gain on our costless collar commodity derivative contracts resulting from the downward shift in the futures curve of forecasted commodity prices ("forward price curve") for crude oil from January 1, 2017 (or the 2017 date on which new contracts were entered into) to September 30, 2017. Derivative (gain) loss, net amounted to a gain of $28 million for the nine months ended September 30, 2016, which consisted of a $56 million fair value gain on embedded derivatives, partially offset by a $28 million loss on commodity derivative contracts resulting from the upward shift in the same forward price curve from January 1, 2016 (or the 2016 date on which prior year contracts were entered into) to September 30, 2016.

Refer to Item 3, "Quantitative and Qualitative Disclosures about Market Risk", for a list of our outstanding commodity derivative contracts as of October 11, 2017.

Loss on Sale of Properties. During the first nine months of 2017, we sold our interests in the FBIR Assets for net cash proceeds of $501 million, which resulted in a pre-tax loss on sale of $402 million. During the first nine months of 2016, we sold our interests in the North Ward Estes properties for net cash proceeds of $295 million, which resulted in a pre-tax loss on sale of $188 million as of September 30, 2016. There were no other property divestitures resulting in a significant gain or loss on sale during the first nine months of 2017 or 2016.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2017	2016
Notes	$ 99,675	$ 145,653
Amortization of debt issue costs, discounts and premiums	22,927	72,389
Credit agreement	20,054	25,655
Other	1,046	1,570
Capitalized interest	(61)	(122)
Total	$ 143,641	$ 245,145

The decrease in interest expense of $102 million between periods was mainly attributable to a decrease in amortization of debt issue costs, discounts and premiums and lower interest costs incurred on our notes during the first nine months of 2017 as compared to the first nine months of 2016. The decrease in amortization of debt issue costs, discounts and premiums of $49 million was due to (i) a $29 million decrease in debt discount and debt issue cost amortization related to the exchange and subsequent conversion to common stock of $1.6 billion of notes during 2016, (ii) a non-cash charge of $14 million for the acceleration of unamortized debt discounts in connection with the August 2016 induced exchange of a portion of our Mandatory Convertible Notes, and (iii) a $6 million non-cash charge for the acceleration of unamortized debt issuance costs in connection with a reduction of the aggregate commitments under our credit agreement in March 2016. The $46 million decrease in note interest was due to (i) the conversions of the New Convertible Notes in May 2016 and

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the Mandatory Convertible Notes in the second half of 2016, resulting in a $34 million decrease in note interest during the first nine months of 2017, and (ii) the redemption of the 2018 Senior Subordinated Notes in February 2017, resulting in a $12 million decrease between periods. Refer to the “Long-Term Debt” footnote in the notes to condensed consolidated financial statements for more information on these debt transactions.

Our weighted average debt outstanding during the first nine months of 2017 was $3.3 billion versus $5.2 billion for the first nine months of 2016. Our weighted average effective cash interest rate was 4.8% during the first nine months of 2017 compared to 4.4% for the first nine months of 2016.

Gain (Loss) on Extinguishment of Debt. During the first nine months of 2017, we redeemed all of the remaining $275 million aggregate principal amount of 2018 Senior Subordinated Notes and recognized a $2 million loss on extinguishment of debt. During the first nine months of 2016, we recognized a net loss on extinguishment of debt of $42 million. In March 2016, we completed the exchange of $477 million aggregate principal amount of our senior notes and senior subordinated notes for the same aggregate principal amount of New Convertible Notes, and recognized a $91 million gain on extinguishment of debt. Subsequently, during the second quarter of 2016, the holders of the New Convertible Notes voluntarily converted all $477 million aggregate principal amount of the New Convertible Notes for approximately 41.8 million shares of our common stock, and we recognized a $188 million loss on extinguishment of debt upon conversion. In June and July 2016, we completed the exchange of $1.1 billion aggregate principal amount of our senior notes, convertible senior notes and senior subordinated notes for the same aggregate principal amount of Mandatory Convertible Notes, and recognized a $57 million gain on extinguishment of debt. Subsequently in July 2016, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 33.2 million shares of our common stock, and we recognized a $3 million gain on extinguishment of debt upon conversion. In August 2016, we induced the exchange of an additional $38 million aggregate principal amount of the Mandatory Convertible Notes for approximately 4.9 million shares of our common stock, and we recognized $4 million of debt inducement expense. Refer to the “Long-Term Debt” footnote in the notes to condensed consolidated financial statements for more information on these debt transactions.

Income Tax Expense (Benefit). Income tax benefit for the first nine months of 2017 totaled $320 million as compared to $182 million of income tax expense for the first nine months of 2016, a decrease of $502 million that was mainly related to (i) a $454 million non-cash charge in the third quarter of 2016 resulting from an ownership shift as defined under Section 382 of the Internal Revenue Code which will limit our usage of certain net operating losses and tax credits in the future, as discussed in the “Income Taxes” footnote in the notes to condensed consolidated financial statements, (ii) $77 million of permanent tax differences recognized during the first nine months of 2016 associated with the issuance and subsequent conversion of the New Convertible Notes and the Mandatory Convertible Notes, and (iii) the partial release of a valuation allowance on net operating losses totaling $41 million in connection with the sale of the FBIR Assets in the third quarter of 2017. These decreases in income tax expense were partially offset by $224 million in lower pre-tax loss between periods.

Our effective tax rates for the periods ending September 30, 2017 and 2016 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Excluding the impact of the Section 382 limitation discussed above, our overall effective tax rate increased from 27.7% for the first nine months of 2016 to 42.1% for the first nine months of 2017. This increase is mainly the result of (i) $77 million of permanent tax differences recognized during the first nine months of 2016 associated with the issuance and subsequent conversion of the New Convertible Notes and the Mandatory Convertible Notes, and (ii) the partial release of a valuation allowance on net operating losses totaling $41 million in connection with the sale of the FBIR Assets in the third quarter of 2017.

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Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

	Three Months Ended September 30,	
	2017	2016
Net production		
Oil (MMBbl)	7.1	7.8
NGLs (MMBbl)	1.8	1.6
Natural gas (Bcf)	10.2	9.9
Total production (MMBOE)	10.5	11.0
Net sales (in millions)		
Oil (1)	$ 289.4	$ 283.8
NGLs	21.3	14.0
Natural gas	13.5	17.8
Total oil, NGL and natural gas sales	$ 324.2	$ 315.6
Average sales prices		
Oil (per Bbl) (1)	$ 41.03	$ 36.58
Effect of oil hedges on average price (per Bbl)	0.66	5.30
Oil net of hedging (per Bbl)	$ 41.69	$ 41.88
Weighted average NYMEX price (per Bbl) (2)	$ 48.24	$ 44.93
NGLs (per Bbl)	$ 12.06	$ 8.65
Natural gas (per Mcf)	$ 1.32	$ 1.79
Weighted average NYMEX price (per MMBtu) (2)	$ 2.89	$ 2.93
Cost and expenses (per BOE)		
Lease operating expenses	$ 8.61	$ 7.98
Production taxes	$ 2.61	$ 2.39
Depreciation, depletion and amortization	$ 20.23	$ 25.80
General and administrative	$ 2.86	$ 3.07

(1) Before consideration of hedging transactions.

(2) Average NYMEX pricing weighted for monthly production volumes.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $9 million to $324 million when comparing the third quarter of 2017 to the same period in 2016. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes decreased 9%, while our NGL and natural gas sales volumes increased 9% and 3%, respectively, between periods. The oil volume decrease between periods was primarily attributable to normal field production decline across several of our areas resulting from reduced drilling and completion activity during the second half of 2016 and the first nine months of 2017 in response to the depressed commodity price environment. In addition, we completed certain oil and gas property divestitures during the second half of 2016 and 2017, which negatively impacted oil production in the third quarter of 2017 by 385 MBbl. These decreases were partially offset by new wells drilled and completed in the Williston Basin and DJ Basin which added 1,700 MBbl and 530 MBbl, respectively, of oil production during the third quarter of 2017 as compared to the third quarter of 2016. The NGL volume increase between periods was primarily due to new wells drilled and completed in the Williston Basin, partially offset by normal field production decline. The gas volume increase between periods was primarily due to new wells drilled and completed at our Williston Basin and DJ Basin properties which resulted in 2,465 MMcf and 215 MMcf, respectively, of additional gas volumes during the third quarter of 2017 as compared to the third quarter of 2016. These increases were partially offset by normal field production decline across several of our areas, as well as 2016 and 2017 property divestitures which negatively impacted gas production in the third quarter of 2017 by 185 MMcf.

The overall production-related decrease in net revenue was offset by increases in the average sales price realized for oil and NGLs. Our average price for oil (before the effects of hedging) and NGLs increased 12% and 39%, respectively, between periods. These increases were partially offset by a decrease in the average sales price realized for natural gas of 26% in the third quarter of 2017 compared to 2016. Our average sales price realized for oil is impacted by deficiency payments we are making under two physical delivery contracts at our Redtail field due to our inability to meet the minimum volume commitments under these contracts. During the three months ended September 30, 2017 and 2016, our total average sales price realized for oil was $2.46 per Bbl lower and $1.59 per Bbl lower,

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respectively, as a result of these deficiency payments. These agreements will continue to negatively impact the price we receive for oil from our Redtail field through April 2020, when the contracts terminate. Refer to the "Commitments and Contingencies" footnote in the notes to condensed consolidated financial statements for more information on these physical delivery contracts and the related deficiency payments.

Lease Operating Expenses. Our LOE during the third quarter of 2017 were $91 million, a $3 million increase over the same period in 2016. This increase was primarily due to new wells put on production in the DJ Basin and Williston Basin during 2017, largely offset by a decline in the costs of oilfield goods and services resulting from the general downturn in the oil and gas industry, as well as cost reduction measures we have implemented.

Our lease operating expenses on a BOE basis also increased when comparing the third quarter of 2017 to the same 2016 period. LOE per BOE amounted to $8.61 during the third quarter of 2017, which represents an increase of $0.63 per BOE (or 8%) from the third quarter of 2016. This increase was mainly due to lower overall production volumes between periods.

Production Taxes. Our production taxes during the third quarter of 2017 were $27 million, a $1 million increase over the same period in 2016. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis remained relatively consistent at 8.5% and 8.4% for the third quarter of 2017 and 2016, respectively.

Depreciation, Depletion and Amortization. Our DD&A expense decreased $72 million in 2017 as compared to the third quarter of 2016. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30,	
	2017	2016
Depletion	$ 207,555	$ 279,169
Depreciation	1,898	2,120
Accretion of asset retirement obligations	3,393	3,280
Total	$ 212,846	$ 284,569

DD&A decreased between periods due to $72 million in lower depletion expense, consisting of a $62 million decrease related to a lower depletion rate between periods and a $10 million decrease due to lower overall production volumes during the third quarter of 2017. On a BOE basis, our overall DD&A rate of $20.23 for the third quarter of 2017 was 22% lower than the rate of $25.80 for the same period in 2016. The primary factors contributing to this lower DD&A rate were (i) an increase to proved and proved developed reserves over the last twelve months (excluding the effect of divestitures) mainly due to higher average oil and natural gas prices used to calculate our reserves, as well as upward performance revisions, extensions and discoveries in our Williston Basin area, and (ii) the impact of property divestitures over the past twelve months. These factors that positively impacted our DD&A rate were partially offset by $721 million in drilling and development expenditures over the past twelve months.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $7 million for the third quarter of 2017 as compared to the same period in 2016. The components of our exploration and impairment expense were as follows (in thousands):

	Three Months Ended September 30,	
	2017	2016
Exploration	$ 7,033	$ 8,747
Impairment	10,624	15,546
Total	$ 17,657	$ 24,293

Impairment expense for the third quarter of 2017 and 2016 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties.

General and Administrative Expenses. We report G&A expenses net of third-party reimbursements and internal allocations. The components of our G&A expenses were as follows (in thousands):

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	Three Months Ended September 30,	
	2017	2016
General and administrative expenses	$ 56,061	$ 62,251
Reimbursements and allocations	(25,977)	(28,343)
General and administrative expenses, net	$ 30,084	$ 33,908

G&A expense before reimbursements and allocations decreased $6 million during the third quarter of 2017 as compared to the same period in 2016 primarily due to lower employee compensation. Employee compensation decreased $8 million for the third quarter of 2017 as compared to the same period in 2016 primarily due to reductions in personnel over the past twelve months.

Our general and administrative expenses on a BOE basis also decreased when comparing the third quarter of 2017 to the same 2016 period. G&A expense per BOE amounted to $2.86 during the third quarter of 2017, which represents a decrease of $0.21 per BOE (or 7%) from the third quarter of 2016. This decrease was mainly due to lower employee compensation, partially offset by lower overall production volumes between periods.

Derivative (Gain) Loss, Net. Our commodity derivative contracts and embedded derivatives are marked to market each quarter with fair value gains and losses recognized immediately in earnings as derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment to or from the counterparty. Derivative (gain) loss, net amounted to a loss of $31 million for the three months ended September 30, 2017, which consisted of a $36 million loss on our costless collar commodity derivative contracts resulting from the upward shift in the forward price curve for crude oil from July 1, 2017 (or the 2017 date on which new contracts were entered into) to September 30, 2017, partially offset by a $5 million fair value gain on our long-term crude oil sales and delivery contract. Derivative (gain) loss, net amounted to a gain of $30 million for the three months ended September 30, 2016, which consisted of a $22 million gain on commodity derivative contracts resulting from the downward shift in the same forward price curve from July 1, 2016 (or the 2016 date on which prior year contracts were entered into) to September 30, 2016, as well as an $8 million fair value gain on embedded derivatives.

Refer to Item 3, “Quantitative and Qualitative Disclosures about Market Risk”, for a list of our outstanding commodity derivative contracts as of October 11, 2017.

Loss on Sale of Properties. During the third quarter of 2017, we sold our interests in the FBIR Assets for net cash proceeds of $501 million, which resulted in a pre-tax loss on sale of $402 million. During the third quarter of 2016, we sold our interests in the North Ward Estes properties for net cash proceeds of $295 million, which resulted in a pre-tax loss on sale of $188 million as of September 30, 2016. There were no other property divestitures resulting in a significant gain or loss on sale during the third quarter of 2017 or 2016.

Interest Expense. The components of our interest expense were as follows (in thousands):

Three Months Ended

	September 30,	
	2017	2016
Notes	$ 32,712	$ 42,749
Amortization of debt issue costs, discounts and premiums	7,705	33,439
Credit agreement	6,969	8,060
Other	343	358
Capitalized interest	(36)	(28)
Total	$ 47,693	$ 84,578

The decrease in interest expense of $37 million between periods was mainly attributable to a decrease in amortization of debt issue costs, discounts and premiums and lower interest costs incurred on our notes during the third quarter of 2017 as compared to the third quarter of 2016. The decrease in amortization of debt issue costs, discounts and premiums of $26 million was primarily due to (i) a non-cash charge of $14 million for the acceleration of unamortized debt discounts in connection with the August 2016 induced exchange of a portion of our Mandatory Convertible Notes, and (ii) a $12 million decrease in debt discount and debt issue cost amortization related to the exchange and subsequent conversion to common stock of $1.1 billion of Mandatory Convertible Notes during 2016. The $10 million decrease in note interest was due to (i) the conversions of the Mandatory Convertible Notes in the second half of 2016, resulting in a $6 million decrease in note interest during the third quarter of 2017, and (ii) the redemption of the 2018 Senior Subordinated Notes in February 2017, resulting in a $4 million decrease between periods. Refer to the “Long-Term Debt” footnote in the notes to condensed consolidated financial statements for more information on these debt transactions.

Our weighted average debt outstanding during the third quarter of 2017 was $3.3 billion versus $4.6 billion for the third quarter of 2016. Our weighted average effective cash interest rate was 4.8% during the third quarter of 2017 compared to 4.4% for the third quarter of 2016.

Gain (Loss) on Extinguishment of Debt. We did not recognize any gain or loss on extinguishment of debt during the third quarter of 2017. During the third quarter of 2016, we recognized a net gain on extinguishment of debt of $47 million. In July 2016, we completed the exchange of $964 million aggregate principal amount of our senior notes, convertible senior notes and senior subordinated notes for the same aggregate principal amount of Mandatory Convertible Notes, and recognized a $48 million gain on extinguishment of debt. Subsequently in July 2016, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 33.2 million shares of our common stock, and we recognized a $3 million gain on extinguishment of debt upon conversion. In August 2016, we induced the exchange of an additional $38 million aggregate principal amount of the Mandatory Convertible Notes for approximately 4.9 million shares of our common stock, and we recognized $4 million of debt inducement expense. Refer to the “Long-Term Debt” footnote in the notes to condensed consolidated financial statements for more information on these debt transactions.

Income Tax Expense (Benefit). Income tax benefit for the third quarter of 2017 totaled $242 million as compared to $358 million of income tax expense for the third quarter of 2016, a decrease of $600 million that was mainly related to (i) a $454 million non-cash charge in the third quarter of 2016 resulting from an ownership shift as defined under Section 382 of the Internal Revenue Code which will limit our usage of certain net operating losses and tax credits in the future, as discussed in the “Income Taxes” footnote in the notes to condensed consolidated financial statements, (ii) $193 million in higher pre-tax loss between periods, (iii) the partial release of a valuation allowance on net operating losses totaling $41 million in connection with the sale of the FBIR Assets in the third quarter of 2017, and (iv) $20 million of permanent tax differences recognized during the third quarter of 2016 associated with the issuance and subsequent conversion of the Mandatory Convertible Notes during that period.

Our effective tax rates for the periods ending September 30, 2017 and 2016 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Excluding the impact of the Section 382 limitation discussed above, our overall effective tax rate increased from 28.9% for the third quarter of 2016 to 45.8% for the third quarter of 2017. This increase is mainly the result of (i) the partial release of a valuation allowance on net operating losses totaling $41 million in connection with the sale of the FBIR Assets in the third quarter of 2017, and (ii) $20 million of permanent tax differences recognized during the third quarter of 2016 associated with the issuance and subsequent conversion of the Mandatory Convertible Notes during that period.

Liquidity and Capital Resources

Overview. At September 30, 2017, we had $11 million of cash on hand and $4.7 billion of equity, while at December 31, 2016, we had $56 million of cash on hand and $5.1 billion of equity.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity hedge contracts. Oil accounted for 68% and 72% of our total production in the first nine months of 2017 and 2016, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in NGL or natural gas prices. As of October 11, 2017, we had derivative contracts covering the sale of approximately 59% of our forecasted oil production volumes for the remainder of 2017. For a list of all of our outstanding derivatives as of October 11, 2017, refer to Item 3, “Quantitative and Qualitative Disclosures about Market Risk”.

During the first nine months of 2017, we generated $290 million of cash provided by operating activities, a decrease of $68 million from the same period in 2016. Cash provided by operating activities decreased primarily due to lower crude oil and natural gas production volumes and a decrease in cash settlements received on our derivative contracts, as well as higher production taxes during the first nine months of 2017. These negative factors were partially offset by higher realized sales prices for oil, NGLs and natural gas, as well as lower cash interest expense, lease operating expenses, exploration costs and general and administrative expenses during the first nine months of 2017 as compared to the same period in 2016. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and for more information on increases and decreases in certain expenses between periods.

During the first nine months of 2017, cash flows from operating activities and cash on hand plus $916 million in proceeds from the sale of oil and gas properties were used to finance $617 million of drilling and development expenditures, $350 million of net repayments under our credit agreement, the redemption of the remaining $275 million of 2018 Senior Subordinated Notes and $18 million of oil and gas property acquisitions.

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Exploration and Development Expenditures. The following table details our exploration and development expenditures incurred by core area (in thousands):

	Nine Months Ended September 30,	
	2017	2016
Northern Rocky Mountains	$ 465,789	$ 242,701
Central Rocky Mountains	269,361	152,542
Permian Basin (1)	-	33,264
Other (2)	6,522	3,138
Total incurred	$ 741,672	$ 431,645

(1) In July 2016, we sold our enhanced oil recovery project at North Ward Estes.
(2) Other primarily includes non-core oil and gas properties located in Colorado, Mississippi, North Dakota, Texas and Wyoming.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2017 exploration and development ("E&D") budget is $950 million, which we expect to fund substantially with net cash provided by operating activities, proceeds from property divestitures or borrowings under our credit facility. The 2017 E&D budget represents an increase over the $554 million incurred on E&D expenditures during 2016. We believe that should additional attractive acquisition opportunities arise or E&D expenditures exceed $950 million, we will be able to finance additional capital expenditures through agreements with industry partners, divestitures of certain oil and gas property interests, borrowings under our credit agreement or by accessing the capital markets. Our level of E&D expenditures is largely discretionary and the amount of funds we devote to any particular activity may increase or decrease significantly depending on commodity prices, cash flows, available opportunities and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plan over the next 12 months and for the foreseeable future. With our expected cash flow streams, commodity price hedging strategies, current liquidity levels (including availability under our credit agreement), access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs and debt repayments, comply with our debt covenants, and meet other obligations that may arise from our oil and gas operations.

Credit Agreement. Whiting Oil and Gas, our wholly owned subsidiary, has a credit agreement with a syndicate of banks that as of September 30, 2017 had a borrowing base and aggregate commitments of $2.5 billion. As of September 30, 2017, we had $2.3 billion of available borrowing capacity, which was net of $200 million in borrowings and $9 million in letters of credit outstanding.

The borrowing base under the credit agreement is determined at the discretion of our lenders, based on the collateral value of our proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Because oil and gas prices are principal inputs into the valuation of our reserves, if current or projected oil and gas prices decline from their current levels, our borrowing base could be reduced at the next redetermination date or during future redeterminations. Upon a redetermination of our borrowing base, either on a periodic or special redetermination date, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt outstanding under the credit agreement. In October 2017, the borrowing base and aggregate commitments under the facility were reduced to $2.3 billion in connection with the November 1, 2017 regular borrowing base redetermination, and was primarily the result of the sale of our FBIR Assets on September 1, 2017.

A portion of the revolving credit facility in an aggregate amount not to exceed $50 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of September 30, 2017, $41 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until December 2019, when the credit agreement expires and all outstanding borrowings are due. Interest under the revolving credit facility accrues at our option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, we also incur commitment fees as set forth in the table below on the unused portion of the aggregate commitments of the lenders under the revolving credit facility.

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Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.50%	2.50%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.75%	2.75%	0.50%
Greater than or equal to 0.90 to 1.0	2.00%	3.00%	0.50%

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. However, the credit agreement permits us and certain of our subsidiaries to issue second lien indebtedness of up to $1.0 billion subject to certain conditions and limitations. Except for limited exceptions, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of our restricted subsidiaries (as defined in the credit agreement). The credit agreement requires us, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0, (ii) a total senior secured debt to the last four quarters' EBITDAX ratio of less than 3.0 to 1.0 during the Interim Covenant Period (defined below), and thereafter a total debt to EBITDAX ratio of less than 4.0 to 1.0, and (iii) a ratio of the last four quarters' EBITDAX to consolidated cash interest charges of not less than 2.25 to 1.0 during the Interim Covenant Period. Under the credit agreement, the "Interim Covenant Period" is defined as the period from June 30, 2015 until the earlier of (i) April 1, 2018 or (ii) the commencement of an investment-grade debt rating period (as defined in the credit agreement). We were in compliance with our covenants under the credit agreement as of September 30, 2017. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

For further information on the loan security related to our credit agreement, refer to the "Long-Term Debt" footnote in the notes to condensed consolidated financial statements.

Senior Notes and Senior Subordinated Notes. In March 2015, we issued at par $750 million of 6.25% Senior Notes due April 2023 (the "2023 Senior Notes"). In September 2013, we issued at par $1.1 billion of 5.0% Senior Notes due March 2019 (the "2019 Senior Notes") and $800 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 2021 (collectively the "2021 Senior Notes" and together with the 2023 Senior Notes and the 2019 Senior Notes, the "Senior Notes"). In September 2010, we issued at par $350 million of 6.5% Senior Subordinated Notes due October 2018 (the "2018 Senior Subordinated Notes").

Exchange of Senior Notes and Senior Subordinated Notes for Convertible Notes. During 2016, we exchanged (i) $75 million aggregate principal amount of our 2018 Senior Subordinated Notes, (ii) $139 million aggregate principal amount of our 2019 Senior Notes, (iii) $326 million aggregate principal amount of our 2021 Senior Notes, and (iv) $342 million aggregate principal amount of our 2023 Senior Notes, for the same aggregate principal amount of convertible notes. Subsequently during 2016, all $882 million aggregate principal amount of these convertible notes was converted into approximately 86.4 million shares of our common stock pursuant to the terms of the notes.

Redemption of 2018 Senior Subordinated Notes. On February 2, 2017, we paid $281 million to redeem all of the then outstanding $275 million aggregate principal amount of our 2018 Senior Subordinated Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the notes. We financed the redemption with borrowings under our credit agreement. As of March 31, 2017, no 2018 Senior Subordinated Notes remained outstanding.

2020 Convertible Senior Notes. In March 2015, we issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the “2020 Convertible Senior Notes”). During 2016, we exchanged $688 million aggregate principal amount of our 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Subsequently during 2016, all $688 million aggregate principal amount of these mandatory convertible senior notes was converted into approximately 71.1 million shares of our common stock pursuant to the terms of the notes.

For the remaining $562 million aggregate principal amount of 2020 Convertible Senior Notes, we have the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at our election. Our intent is to settle the principal amount of the 2020 Convertible Senior Notes in cash upon conversion. Prior to January 1, 2020, the 2020 Convertible Senior Notes will be convertible at the holder’s option only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on June 30, 2015 (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading

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day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price per $1,000 principal amount of the 2020 Convertible Senior Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of our common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after January 1, 2020, the 2020 Convertible Senior Notes will be convertible at any time until the second scheduled trading day immediately preceding the April 1, 2020 maturity date of the notes. The notes will be convertible at an initial conversion rate of 25.6410 shares of our common stock per $1,000 principal amount of the notes, which is equivalent to an initial conversion price of approximately $39.00. The conversion rate will be subject to adjustment in some events, including if stockholders authorize the proposed reverse stock split at our November 8, 2017 special meeting, and our Board of Directors subsequently implements it. In addition, following certain corporate events that occur prior to the maturity date, we will increase, in certain circumstances, the conversion rate for a holder who elects to convert its 2020 Convertible Senior Notes in connection with such corporate event. As of September 30, 2017, none of the contingent conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met.

Note Covenants. The indentures governing the Senior Notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas' credit agreement. Additionally, these indentures contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, make certain other restricted payments, redeem or repurchase our capital stock, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of September 30, 2017. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of September 30, 2017 to make future payments under certain contracts, aggregated by category of contractual obligation, for the time periods specified below. This table does not include amounts payable under contracts where we cannot predict with accuracy the amount and timing of such payments, including any amounts we may be obligated to pay under our derivative contracts, as such payments are dependent upon the price of crude oil in effect at the time of settlement, and any penalties that may be incurred for underdelivery under our physical delivery contracts. For further information on these contracts refer to the "Derivative Financial Instruments" footnote in the notes to consolidated financial statements and "Delivery Commitments" in Item 2 of our Annual Report on Form 10-K for the period ended December 31, 2016.

	Payments due by period (in thousands)				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$ 3,005,389	$ -	$ 1,723,484	$ 873,609	$ 408,296

Cash interest expense on debt (2)	442,973	149,808	206,485	73,921	12,759
Asset retirement obligations (3)	161,815	4,517	29,683	7,446	120,169
Water disposal agreement (4)	125,605	17,880	40,200	38,154	29,371
Purchase obligations (5)	24,882	7,656	15,312	1,914	-
Pipeline transportation agreements (6)	57,356	9,284	18,866	16,383	12,823
Drilling rig contracts (7)	12,968	12,129	839	-	-
Leases (8)	16,589	7,504	8,935	150	-
Total	$ 3,847,577	$ 208,778	$ 2,043,804	$ 1,011,577	$ 583,418

(1) Long-term debt consists of the principal amounts of the Senior Notes and the 2020 Convertible Senior Notes, as well as the outstanding borrowings under our credit agreement.

(2) Cash interest expense on the Senior Notes is estimated assuming no principal repayment until the due dates of the instruments. Cash interest expense on the 2020 Convertible Senior Notes is estimated assuming no principal repayments or conversions prior to maturity. Cash interest expense on the credit agreement is estimated assuming no principal borrowings or repayments through the December 2019 instrument due date and a fixed interest rate of 3.7%.

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(3) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related plants, facilities and offshore platforms.

(4) We have one water disposal agreement which expires in 2024, whereby we have contracted for the transportation and disposal of the produced water from our Redtail field. Under the terms of the agreement, we are obligated to provide a minimum volume of produced water or else pay for any deficiencies at the price stipulated in the contract. The obligations reported above represent our minimum financial commitments pursuant to the terms of this contract, however, our actual expenditures under this contract may exceed the minimum commitments presented above.

(5) We have one take-or-pay purchase agreement which expires in 2020, whereby we have committed to buy certain volumes of water for use in the fracture stimulation process on wells we complete in our Redtail field. Under the terms of the agreement, we are obligated to purchase a minimum volume of water or else pay for any deficiencies at the price stipulated in the contract. The purchasing obligations reported above represent our minimum financial commitments pursuant to the terms of this contract, however, our actual expenditures under this contract may exceed the minimum commitments presented above.

(6) We have three pipeline transportation agreements with two different suppliers, expiring in 2022, 2024 and 2025. Under two of these contracts, we have committed to pay fixed monthly reservation fees on dedicated pipelines from our Redtail field for natural gas and NGL transportation capacity, plus a variable charge based on actual transportation volumes. The remaining contract contains a commitment to transport a minimum volume of crude oil via a certain oil gathering system or else pay for any deficiencies at a price stipulated in the contract. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments presented above.

(7) As of September 30, 2017, we had two drilling rigs under long-term contracts expiring in 2018. As of September 30, 2017, early termination of these contracts would require termination penalties of $8 million, which would be in lieu of paying the remaining drilling commitments under these contracts. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments presented above.

(8) We lease 222,900 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2019, 44,500 square feet of office space in Midland, Texas expiring in 2020, and 36,500 square feet of office space in Dickinson, North Dakota expiring in 2020. We have sublet the majority of our office space in Midland, Texas to a third party for the remaining lease term. The offsetting rental income has not been included in the table above.

Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operating, development and exploration activities.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to “Adopted and Recently Issued Accounting Pronouncements” within the “Basis of Presentation” footnote in the notes to condensed consolidated financial statements.

Critical Accounting Policies and Estimates

Information regarding critical accounting policies and estimates is contained in Item 7 of our Annual Report on Form 10 K for the fiscal year ended December 31, 2016. The following is a material update to such critical accounting policies and estimates:

Derivative and Embedded Derivative Instruments. All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the “normal purchase normal sale” exclusion or other derivative scope exceptions. We do not currently apply hedge accounting to any of our outstanding derivative instruments, and as a result, all changes in derivative fair values are recognized currently in earnings.

We determine the recorded amounts of our derivative instruments measured at fair value utilizing third-party valuation specialists. We review these valuations, including the related model inputs and assumptions, and analyze changes in fair value measurements between periods. We corroborate such inputs, calculations and fair value changes using various methodologies, and review unobservable inputs for reasonableness utilizing relevant information from other published sources. When available, we utilize counterparty valuations to assess the reasonableness of our valuations. The values we report in our financial statements change as the assumptions used in these valuations are revised to reflect changes in market conditions (particularly those for oil and natural gas futures) or other factors, many of which are beyond our control.

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We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We primarily utilize costless collars which are generally placed with major financial institutions, as well as swaps and crude oil sales and delivery contracts. We use hedging to help ensure that we have adequate funding for our capital programs and manage returns on our drilling programs and acquisitions. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

We value our costless collars and swaps using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. We value our long-term crude oil sales and delivery contracts based on a probability-weighted income approach which considers various assumptions, including quoted spot prices for commodities, market differentials for crude oil and U.S. Treasury rates. The discount rates used in the fair values of these instruments include a measure of nonperformance risk by the counterparty or us, as appropriate.

In addition, we evaluate the terms of our convertible debt and other contracts, if any, to determine whether they contain embedded components that are required to be bifurcated and accounted for separately as derivative financial instruments.

We valued the embedded derivatives related to our convertible notes using a binomial lattice model which considered various inputs including (i) our common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) recovery rates in the event of default, (iv) default intensity and (v) volatility of our common stock.

We also had an embedded derivative related to our purchase and sale agreement with the buyer of the North Ward Estes properties, which included a contingent payment linked to NYMEX crude oil prices. Prior to settlement of the contingent payment in July 2017, we valued this embedded derivative using a modified Black-Scholes swaption pricing model which considered various assumptions, including quoted forward prices for commodities, time value and volatility factors. The discount rate used in the fair value of this instrument included a measure of the counterparty’s nonperformance risk.

Effects of Inflation and Pricing

As a result of the sustained depressed commodity price environment during 2016 and continuing into 2017, we have experienced lower costs due to a decrease in demand for oil field products and services. The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase in the near term, higher demand in the industry could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

This report contains statements that we believe to be “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 historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we “expect”, “intend”, “plan”, “estimate”, “anticipate”, “believe” or “should” or the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

These risks and uncertainties include, but are not limited to: declines in, or extended periods of low oil, NGL or natural gas prices; our level of success in exploration, development and production activities; risks related to our level of indebtedness, ability to comply with debt covenants and periodic redeterminations of the borrowing base under our credit agreement; impacts to financial statements as a result of impairment write-downs; our ability to successfully complete asset dispositions and the risks related thereto; revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; inaccuracies of our reserve estimates or our assumptions underlying them; risks relating to any unforeseen liabilities of ours; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations; federal and state initiatives relating to the regulation of hydraulic fracturing and air emissions; unforeseen underperformance of or liabilities associated with acquired properties; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; availability of, and risks associated with, transport of oil and gas; our ability to drill producing wells on undeveloped acreage prior to its lease expiration; shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry; the potential impact of changes in laws, including tax reform, that could have a negative effect on the oil and gas industry; cyber security attacks or failures of our telecommunication systems; and other risks described under the caption "Risk Factors" in Item 1A of our Annual Report on Form 10 K for the period ended December 31, 2016. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Quarterly Report on Form 10-Q.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. Based on production for the first nine months of 2017, our income (loss) before income taxes for the nine months ended September 30, 2017 would have moved up or down $89 million for each 10% change in oil prices per Bbl, $7 million for each 10% change in NGL prices per Bbl and $5 million for each 10% change in natural gas prices per Mcf.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars and swaps, although we evaluate and have entered into other forms of derivative instruments as well. Currently, we do not apply hedge accounting, and therefore all changes in commodity derivative fair values are recorded immediately to earnings.

Crude Oil Costless Collars. The collared hedges shown in the table below have the effect of providing a protective floor while allowing us to share in upward pricing movements. The three-way collars, however, do not provide complete protection against declines in crude oil prices due to the fact that when the market price falls below the sub-floor, the minimum price we would receive would be NYMEX plus the difference between the floor and the sub-floor. While these hedges are designed to reduce our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. The fair value of these commodity derivative instruments at September 30, 2017 was a net liability of $3 million. A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of September 30, 2017 would cause an increase of $51 million or a decrease of $41 million, respectively, in this fair value liability.

Our outstanding commodity derivative contracts as of October 11, 2017 are summarized below:

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Sub-Floor/Floor/Ceiling
Three-way collars (1)	Crude oil	10/2017 to 12/2017	1,250,000	$35.00/$45.20/$58.95
	Crude oil	01/2018 to 03/2018	1,250,000	$36.60/$46.60/$56.94
	Crude oil	04/2018 to 06/2018	1,250,000	$36.60/$46.60/$56.94
	Crude oil	07/2018 to 09/2018	1,250,000	$36.60/$46.60/$56.94
	Crude oil	10/2018 to 12/2018	1,250,000	$36.60/$46.60/$56.94
Collars	Crude oil	10/2017 to 12/2017	250,000	$53.00/$70.44

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. The purchased put

establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

Interest Rate Risk

Our quantitative and qualitative disclosures about interest rate risk related to our credit agreement are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2016 and have not materially changed since that report was filed.

In March 2015, we issued 1.25% Convertible Senior Notes due April 2020 (the "2020 Convertible Senior Notes"). As the interest rate on these notes is fixed at 1.25%, we are not subject to any direct risk of loss related to fluctuations in interest rates. However, changes in interest rates do affect the fair value of this debt instrument, which could impact the amount of gain or loss that we recognize in earnings upon conversion of the notes. Refer to the "Long-Term Debt" and "Fair Value Measurements" footnotes in the notes to condensed consolidated financial statements for more information on the material terms and fair values of the 2020 Convertible Senior Notes.

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Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our Senior Vice President and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of September 30, 2017. Based upon their evaluation of these disclosure controls and procedures, the Chairman, President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of September 30, 2017 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended September 30, 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

We are subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. While the outcome of these lawsuits and claims cannot be predicted with certainty, it is management's opinion that the loss for any litigation matters and claims we are involved in that are reasonably possible to occur will not have a material adverse effect, individually or in the aggregate, on our consolidated financial position, cash flows or results of operations.

After the closing of the Kodiak acquisition in December 2014, the U.S. Environmental Protection Agency (the "EPA") contacted us to discuss Kodiak's responses to a June 2014 information request from the EPA under Section 114(a) of the Federal Clean Air Act, as amended (the "CAA"). In addition, in July 2015 and March 2016, we received information requests from the EPA under Section 114(a) of the CAA. The information requests relate to tank batteries used in our Williston Basin operations and our compliance with certain regulatory requirements at those locations for the control of air pollutant emissions from those facilities. We have responded to the EPA's July 2015 and March 2016 information requests, and such responses were also provided to the North Dakota Department of Health (the "NDDoH"), with whom the EPA was coordinating in making the requests.

In connection with the above EPA inquiries, we entered into a settlement with the NDDoH that became effective in November 2016. This settlement addressed approximately 94% of our North Dakota properties owned at the time but did not address our operations on the Fort Berthold Indian Reservation in North Dakota, over which the EPA has sole authority to enforce CAA violations. On September 1, 2017, we completed the sale of our interests in all Fort Berthold Indian Reservation properties that we previously obtained from Kodiak. We are currently engaged in settlement negotiations with the EPA concerning alleged violations of applicable regulations by Kodiak prior to its acquisition, and by us after we acquired the subject properties.

We are also currently engaged in discussions with the Colorado Department of Public Health and Environment (the "CDPHE") concerning certain equipment used in our Redtail facilities and our compliance with various air permits and applicable federal and state air quality laws and regulations over the control of air pollutant emissions from those facilities. We and the CDPHE are currently negotiating the terms of a settlement agreement to resolve this matter.

Item 1A. Risk Factors

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10 K for the fiscal year ended December 31, 2016. No material change to such risk factors has occurred during the nine months ended September 30, 2017.

Item 6. Exhibits

The exhibits listed in the accompanying index to exhibits are filed as part of this Quarterly Report on Form 10 Q.

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(2.1)	Purchase and Sale Agreement, dated August 14, 2017, by and among Whiting Resources Corporation, RimRock Oil & Gas Williston, LLC, Whiting Oil and Gas Corporation and RimRock Oil & Gas Williston Resources, Inc., effective as of September 1, 2017 [Incorporated by reference to Exhibit 2.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on September 6, 2017 (File No. 001-31899)]. *
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Senior Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Senior Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
(101)	The following materials from Whiting Petroleum Corporation's Quarterly Report on Form 10 Q for the quarter ended September 30, 2017 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets as of September 30, 2017 and December 31, 2016, (ii) the Condensed Consolidated Statements of Operations for the Three and Nine Months Ended September 30, 2017 and 2016, (iii) the Condensed Consolidated Statements of Cash Flows for the Nine Months Ended September 30, 2017 and 2016, (iv) the Condensed Consolidated Statements of Equity for the Nine Months Ended September 30, 2017 and 2016 and (v) Notes to Condensed Consolidated Financial Statements.
*	Certain schedules and exhibits have been omitted and Whiting agrees to furnish supplementally to the Securities and Exchange Commission a copy of any omitted schedule or exhibit upon request.

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SIGNATURES

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, on this 26th day of October, 2017.

WHITING PETROLEUM CORPORATION

By /s/ James J. Volker
James J. Volker
Chairman, President and Chief Executive Officer

By /s/ Michael J. Stevens
Michael J. Stevens
Senior Vice President and Chief Financial Officer

By /s/ Sirikka R. Lohoefener
Sirikka R. Lohoefener
Controller and Treasurer