WHITING PETROLEUM CORP
Form 10-Q
October 25, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2013

or

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

For the transition period from _______________ to _______________

Commission file number: 001-31899

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.)
1700 Broadway, Suite 2300 Denver, Colorado (Address of principal executive offices)	80290-2300 (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 T 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 T No £

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

Large accelerated filerT Accelerated filer £ Non-accelerated filer£ Smaller reporting company £

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

Number of shares of the registrant's common stock outstanding at October 15, 2013: 118,654,184 shares.

TABLE OF CONTENTS

	Glossary of Certain Definitions	1

PART I – FINANCIAL INFORMATION

Item 1.	Consolidated Financial Statements (Unaudited)	4
	Consolidated Balance Sheets as of September 30, 2013 and December 31, 2012	4
	Consolidated Statements of Income for the Three and Nine Months Ended September 30, 2013 and 2012	5
	Consolidated Statements of Comprehensive Income for the Three and Nine Months Ended September 30, 2013 and 2012	6
	Consolidated Statements of Cash Flows for the Nine Months Ended September 30, 2013 and 2012	7
	Consolidated Statements of Equity for the Nine Months Ended September 30, 2013 and 2012	8
	Notes to Consolidated Financial Statements	9
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	25
Item 3.	Quantitative and Qualitative Disclosure About Market Risk	42
Item 4.	Controls and Procedures	43

PART II – OTHER INFORMATION

Item 1.	Legal Proceedings	45
Item 1A.	Risk Factors	45
Item 6.	Exhibits	59
	Certification by the Chairman and Chief Executive Officer	
	Certification by the Vice President and Chief Financial Officer	
	Written Statement of the Chairman and Chief Executive Officer	
	Written Statement of the Vice President and Chief Financial Officer	

Table of Contents

GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms "we," "us," "our" or "ours" when used in this report 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:

"3-D seismic" Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

"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 of 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.

"CO2" Carbon dioxide.

"CO2 flood" A tertiary recovery method in which CO2 is injected into a reservoir to enhance hydrocarbon recovery.

"completion" The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

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

"FASB" Financial Accounting Standards Board.

"FASB ASC" The Financial Accounting Standards Board Accounting Standards Codification.

"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.

"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.

“MBbl” One thousand barrels of oil or other liquid hydrocarbons.

“MBOE” One thousand BOE.

Table of Contents

"MBOE/d" One MBOE per day.

"Mcf" One thousand cubic feet of natural gas.

"MMBbl" One million Bbl.

"MMBOE" One million BOE.

"MMBtu" One million British Thermal Units.

"MMcf" One million cubic feet of natural gas.

"MMcf/d" One MMcf per day.

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

"NGL" Natural gas liquid.

"NYMEX" The New York Mercantile Exchange.

"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 many states require plugging of abandoned wells.

"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.

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.

2

Table of Contents

“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.

“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 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.

Table of Contents

PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

WHITING PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS (Unaudited)
(In thousands, except share and per share data)

	September 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,025,579	$ 44,800
Accounts receivable trade, net	361,512	318,265
Prepaid expenses and other	13,723	21,347
Total current assets	1,400,814	384,412
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	9,880,963	8,849,515
Unproved properties	415,748	362,483
Other property and equipment	176,516	141,738
Total property and equipment	10,473,227	9,353,736
Less accumulated depreciation, depletion and amortization	(2,907,055)	(2,590,203)
Total property and equipment, net	7,566,172	6,763,533
Debt issuance costs	51,830	28,748
Other long-term assets	108,157	95,726
TOTAL ASSETS	$ 9,126,973	$ 7,272,419
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 250,000	$ -
Accounts payable trade	92,092	131,370
Accrued capital expenditures	158,813	110,663
Accrued liabilities and other	200,262	180,622
Revenues and royalties payable	195,377	149,692
Taxes payable	61,735	33,283
Derivative liabilities	20,164	21,955
Deferred income taxes	9,993	9,394
Total current liabilities	988,436	636,979
Long-term debt	2,653,991	1,800,000
Deferred income taxes	1,284,178	1,063,681
Derivative liabilities	499	1,678
Production Participation Plan liability	95,815	94,483
Asset retirement obligations	99,059	86,179
Deferred gain on sale	88,238	110,395
Other long-term liabilities	26,697	25,852
Total liabilities	5,236,913	3,819,247
Commitments and contingencies		

Equity:				
Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, no shares authorized, issued or outstanding as of September 30, 2013 and 172,391 shares issued and outstanding as of December 31, 2012		-		-
Common stock, $0.001 par value, 300,000,000 shares authorized; 120,106,602 issued and 118,654,184 outstanding as of September 30, 2013, 118,582,477 issued and 117,631,451 outstanding as of December 31, 2012		120		119
Additional paid-in capital		1,578,033		1,566,717
Accumulated other comprehensive loss		(406)		(1,236)
Retained earnings		2,304,170		1,879,388
Total Whiting shareholders’ equity		3,881,917		3,444,988
Noncontrolling interest		8,143		8,184
Total equity		3,890,060		3,453,172
TOTAL LIABILITIES AND EQUITY	$	9,126,973	$	7,272,419

See notes to consolidated financial statements.

4

Table of Contents

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME (Unaudited)
(In thousands, except per share data)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
REVENUES AND OTHER INCOME:				
Oil, NGL and natural gas sales	$ 706,543	$ 521,195	$ 1,963,525	$ 1,572,648
Gain (loss) on hedging activities	(665)	398	(1,313)	2,285
Amortization of deferred gain on sale	7,750	8,636	23,680	21,281
Gain (loss) on sale of properties	116,274	99	119,706	(263)
Interest income and other	1,083	154	2,327	412
Total revenues and other income	830,985	530,482	2,107,925	1,596,363
COSTS AND EXPENSES:				
Lease operating	109,106	93,859	314,064	278,153
Production taxes	61,143	43,519	166,228	128,893
Depreciation, depletion and amortization	219,530	179,587	644,135	496,296
Exploration and impairment	47,092	23,882	127,765	79,362
General and administrative	50,368	25,034	108,466	84,611
Interest expense	24,988	18,734	69,579	55,095
Change in Production Participation Plan liability	(10,798)	6,217	1,332	6,199
Commodity derivative (gain) loss, net	24,269	6,421	25,334	(64,200)
Total costs and expenses	525,698	397,253	1,456,903	1,064,409
INCOME BEFORE INCOME TAXES	305,287	133,229	651,022	531,954
INCOME TAX EXPENSE (BENEFIT):				
Current	7,220	(1,859)	5,131	676
Deferred	93,976	51,975	220,612	198,868
Total income tax expense	101,196	50,116	225,743	199,544
NET INCOME	204,091	83,113	425,279	332,410
Net loss attributable to noncontrolling interest	10	21	41	76
NET INCOME AVAILABLE TO SHAREHOLDERS	204,101	83,134	425,320	332,486

Preferred stock dividends	-	(269)	(538)	(808)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 204,101	$ 82,865	$ 424,782	$ 331,678
EARNINGS PER COMMON SHARE:				
Basic	$ 1.72	$ 0.70	$ 3.60	$ 2.82
Diluted	$ 1.71	$ 0.70	$ 3.56	$ 2.79
WEIGHTED AVERAGE SHARES OUTSTANDING:				
Basic	118,654	117,631	118,127	117,590
Diluted	119,507	118,924	119,511	118,968

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
NET INCOME	$ 204,091	$ 83,113	$ 425,279	$ 332,410
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:				
OCI amortization on de-designated hedges(1)(2)	420	(251)	830	(1,442)
Total other comprehensive income (loss), net of tax	420	(251)	830	(1,442)
COMPREHENSIVE INCOME	204,511	82,862	426,109	330,968
Comprehensive loss attributable to noncontrolling interest	10	21	41	76
COMPREHENSIVE INCOME ATTRIBUTABLE TO WHITING	$ 204,521	$ 82,883	$ 426,150	$ 331,044

(1) Presented net of income tax expense of $245 and income tax benefit of $147 for the three months ended September 30, 2013 and 2012, respectively, and income tax expense of $483 and income tax benefit of $843 for the nine months ended September 30, 2013 and 2012, respectively.
(2) These gain (loss) amounts on de-designated hedges are reclassified from accumulated other comprehensive income (“AOCI”) to gain (loss) on hedging activities in the consolidated statements of income.

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(In thousands)

	Nine Months Ended September 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 425,279	$ 332,410
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	644,135	496,296
Deferred income tax expense	220,612	198,868
Amortization of debt issuance costs and debt premium	7,800	7,051
Stock-based compensation	16,830	13,498
Amortization of deferred gain on sale	(23,680)	(21,281)
(Gain) loss on sale of properties	(119,706)	263
Undeveloped leasehold and oil and gas property impairments	56,130	45,770
Exploratory dry hole costs	21,150	2,140
Change in Production Participation Plan liability	1,332	6,199
Non-cash portion of derivative (gains) losses	740	(91,763)
Other, net	(8,109)	(14,311)
Changes in current assets and liabilities:		
Accounts receivable trade	(43,247)	(82,837)
Prepaid expenses and other	(1,442)	664
Accounts payable trade and accrued liabilities	(17,956)	80,525
Revenues and royalties payable	45,807	33,268
Taxes payable	28,452	11,185
Net cash provided by operating activities	1,254,127	1,017,945
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(438,329)	(102,978)
Drilling and development capital expenditures	(1,669,979)	(1,509,582)
Proceeds from sale of oil and gas properties	819,612	69,190
Net proceeds from sale of 18,400,000 units in Whiting USA Trust II	-	322,212
Issuance of note receivable	(10,530)	-
Cash paid for investing derivatives	(44,900)	-
Cash settlements received on investing derivatives	2,371	-
Net cash used in investing activities	(1,341,755)	(1,221,158)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of 5% Senior Notes due 2019	1,100,000	-
Issuance of 5.75% Senior Notes due 2021	1,204,000	-

Preferred stock dividends paid		(538)		(808)
Long-term borrowings under credit agreement		1,860,000		1,750,000
Repayments of long-term borrowings under credit agreement		(3,060,000)		(1,530,000)
Debt issuance costs		(29,541)		(20)
Restricted stock used for tax withholdings		(5,514)		(5,695)
Net cash provided by financing activities		1,068,407		213,477
NET CHANGE IN CASH AND CASH EQUIVALENTS		980,779		10,264
CASH AND CASH EQUIVALENTS:				
Beginning of period		44,800		15,811
End of period	$	1,025,579	$	26,075
NONCASH INVESTING ACTIVITIES:				
Accrued capital expenditures	$	158,813	$	112,137

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY (Unaudited)
(In thousands)

	Preferred Stock		Common Stock		Additional Paid-in	Accumulated Other Comprehensive Income (Loss)	Retained	Total Whiting Shareholders'	Noncontrolling	Total
	Shares	Amount	Shares	Amount	Capital		Earnings	Equity	Interest	Equity
BALANCES-January 1, 2012	172	$ -	118,105	$ 118	$ 1,554,223	$ 240	$ 1,466,276	$ 3,020,857	$ 8,274	$ 3,029,131
Net income (loss)	-	-	-	-	-	-	332,486	332,486	(76)	332,410
Other comprehensive income (loss)	-	-	-	-	-	(1,442)	-	(1,442)	-	(1,442)
Restricted stock issued	-	-	592	1	(1)	-	-	-	-	-
Restricted stock forfeited	-	-	(7)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(106)	-	(5,695)	-	-	(5,695)	-	(5,695)
Stock-based compensation	-	-	-	-	13,498	-	-	13,498	-	13,498
Preferred dividends paid	-	-	-	-	-	-	(808)	(808)	-	(808)
BALANCES-September 30, 2012	172	$ -	118,584	$ 119	$ 1,562,025	$ (1,202)	$ 1,797,954	$ 3,358,896	$ 8,198	$ 3,367,094
BALANCES-January 1, 2013	172	$ -	118,582	$ 119	$ 1,566,717	$ (1,236)	$ 1,879,388	$ 3,444,988	$ 8,184	$ 3,453,172
Net income (loss)	-	-	-	-	-	-	425,320	425,320	(41)	425,279
Other comprehensive income (loss)	-	-	-	-	-	830	-	830	-	830
Conversion of preferred stock to common	(172)	-	794	1	-	-	-	1	-	1
Restricted stock issued	-	-	941	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(96)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(114)	-	(5,514)	-	-	(5,514)	-	(5,514)
Stock-based compensation	-	-	-	-	16,830	-	-	16,830	-	16,830
Preferred dividends paid	-	-	-	-	-	-	(538)	(538)	-	(538)
BALANCES-September 30, 2013	-	$ -	120,107	$ 120	$ 1,578,033	$ (406)	$ 2,304,170	$ 3,881,917	$ 8,143	$ 3,890,060

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company that explores for, develops, acquires and produces crude oil, NGLs and natural gas primarily in the Rocky Mountains, Permian Basin, Michigan, Gulf Coast and Mid-Continent regions 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.

Consolidated Financial Statements—The unaudited consolidated financial statements include the accounts of Whiting Petroleum Corporation, its consolidated subsidiaries and Whiting's pro rata share of the accounts of Whiting USA Trust I ("Trust I") pursuant to Whiting's 15.8% ownership interest in Trust I. 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 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. Whiting's 2012 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Quarterly Report on Form 10-Q. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in Whiting's 2012 Annual Report on Form 10-K.

Earnings Per Share—Basic earnings per common share is calculated by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing adjusted net income available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method, as well as convertible perpetual preferred stock using the if-converted method. In the computation of diluted earnings per share, excess tax benefits that would be created upon the assumed vesting of unvested restricted shares or the assumed exercise of stock options (i.e. hypothetical excess tax benefits) are included in the assumed proceeds component of the treasury share method to the extent that such excess tax benefits are more likely than not to be realized. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

2. ACQUISITIONS AND DIVESTITURES

2013 Acquisitions

On September 20, 2013, the Company completed the acquisition of approximately 39,300 gross (17,300 net) acres, including interests in 121 producing oil and gas wells and undeveloped acreage, in the Williston Basin located in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an aggregate unadjusted purchase price of $260.0 million. Revenue and earnings from these properties since the September 20, 2013 acquisition date, which are included in the consolidated statements of income for the three and nine months ended September 30, 2013, are not material. Disclosures of pro forma revenues and net income for the acquisition of these wells are not material and have not been presented accordingly.

Table of Contents

The acquisition was recorded using the purchase method of accounting. The following table summarizes the preliminary allocation of the $261.3 million adjusted purchase price (which is still subject to post-closing adjustments) to the tangible assets acquired and liabilities assumed in this acquisition oil and gas properties. As the purchase price is further adjusted for post-close adjustments and as oil and gas property valuations are completed, the final purchase price allocation may result in a different allocation to the tangible assets from that which is presented in the table below (in thousands):

Purchase price	$261,313
Allocation of purchase price:	
Proved properties	$234,608
Unproved properties	27,335
Oil in tank inventory	692
Accounts receivable	578
Asset retirement obligations	(1,900)
Total	$261,313

2013 Divestitures

On July 15, 2013, the Company completed the sale of its interests in certain oil and gas producing properties located in its enhanced oil recovery projects in the Postle and Northeast Hardesty fields in Texas County, Oklahoma, including the related Dry Trail plant gathering and processing facility, oil delivery pipeline, its entire 60% interest in the Transpetco CO2 pipeline, crude oil swap contracts and certain other related assets and liabilities (collectively the "Postle Properties"), effective April 1, 2013, for a cash purchase price of $816.5 million after selling costs and post-closing adjustments, resulting in a pre-tax gain on sale of $116.4 million. The Company used the net proceeds from this sale to repay a portion of the debt outstanding under its credit agreement. The Postle Properties had estimated proved reserves of 45.1 MMBOE as of December 31, 2012, representing 11.9% of Whiting's proved reserves as of that date, and generated 8% (or 7.6 MBOE/d) of Whiting's June 2013 average daily net production.

Upon closing of the transaction, the following crude oil swaps and any of their related cash settlements as of that date were transferred to the buyer of the Postle Properties:

Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price for Crude Oil (per Bbl)
Apr – Dec 2013	1,677,500	$98.50
Jan – Dec 2014	2,007,500	$94.75
Jan – Dec 2015	1,825,000	$94.75
Jan – Mar 2016	400,400	$93.50
Total	5,910,400	

2012 Acquisitions

On March 22, 2012, the Company completed the acquisition of approximately 13,300 net undeveloped acres in the Missouri Breaks prospect in Richland County, Montana for $33.3 million.

2012 Divestitures

On May 18, 2012, the Company sold a 50% ownership interest in its Belfield gas processing plant, natural gas gathering system, oil gathering system and related facilities located in Stark County, North Dakota for total cash proceeds of $66.2 million. Whiting used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

Table of Contents

On March 28, 2012, the Company completed an initial public offering of units of beneficial interest in Whiting USA Trust II ("Trust II"), selling 18,400,000 Trust II units at $20.00 per unit, which generated net proceeds of $322.3 million after underwriters' fees, offering expenses and post-close adjustments. The Company used the net offering proceeds to repay a portion of the debt outstanding under its credit agreement. The net proceeds from the sale of Trust II units to the public resulted in a deferred gain on sale of $128.2 million. Immediately prior to the closing of the offering, Whiting conveyed a term net profits interest in certain of its oil and gas properties to Trust II in exchange for 100% of the trust's units issued, or 18,400,000 units.

The net profits interest entitles Trust II to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate on the later to occur of (1) December 31, 2021, or (2) the time when 11.79 MMBOE have been produced from the underlying properties and sold. This is the equivalent of 10.61 MMBOE in respect of Trust II's right to receive 90% of the net proceeds from such reserves pursuant to the net profits interest. The conveyance of the net profits interest to Trust II consisted entirely of proved reserves of 10.61 MMBOE as of the January 1, 2012 effective date, representing 3% of Whiting's proved reserves as of December 31, 2011 and 5% (or 4.5 MBOE/d) of its March 2012 average daily net production.

3. LONG-TERM DEBT

Long-term debt, including the current portion, consisted of the following at September 30, 2013 and December 31, 2012 (in thousands):

	September 30, 2013	December 31, 2012
Credit agreement	$ -	$ 1,200,000
7% Senior Subordinated Notes due 2014	250,000	250,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
5% Senior Notes due 2019	1,100,000	-
5.75% Senior Notes due 2021, including unamortized debt premium of $3,991	1,203,991	-
Total debt	$ 2,903,991	$ 1,800,000

Credit Agreement—Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), the Company's wholly-owned subsidiary, has a credit agreement with a syndicate of banks that, as of September 30, 2013, had a borrowing base of $2.15 billion, of which $1.2 billion has been committed by lenders and is available for borrowing. The Company may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.15 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of September 30, 2013, the Company had $1,197.0 million of available borrowing capacity, which is net of $3.0 million in letters of credit with no borrowings outstanding.

In July 2013, upon closing of the sale of the Postle Properties discussed in the Acquisitions and Divestitures footnote, the credit agreement borrowing base and aggregate commitments decreased from $2.5 billion to $2.15 billion. In September 2013, Whiting Oil and Gas entered into an amendment to its existing credit agreement to permit the issuance of up to $2.3 billion of senior notes without a reduction in the borrowing base, and upon completion of the first Senior Notes offering discussed below, it voluntarily reduced the aggregate commitments under the credit agreement from $2.15 billion to $1.2 billion.

The credit agreement provides for interest only payments until April 2016, when the agreement expires and all outstanding borrowings are due. 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 its 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. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 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, 2013, $47.0 million was available for additional letters of credit under the agreement.

Table of Contents

Interest 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 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, the Company also incurs commitment fees, as set forth in the table below on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base, and which are included as a component of interest expense. 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.

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	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	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. 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 net assets of Whiting Oil and Gas. As of September 30, 2013, total restricted net assets were $4,143.5 million, and the amount of retained earnings free from restrictions was $22.0 million. The credit agreement requires the Company, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. The Company was in compliance with its covenants under the credit agreement as of September 30, 2013.

The obligations of Whiting Oil and Gas under the credit agreement are secured by a first lien on substantially all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. The Company has guaranteed the obligations of Whiting Oil and Gas under the credit agreement and has pledged the stock of Whiting Oil and Gas as security for its guarantee.

Senior Notes and Senior Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due February 2014 ("2014 Notes"). The estimated fair value of these notes was $255.0 million as of September 30, 2013, based on quoted market prices for these debt securities, and such fair value is therefore designated as Level 1 within the valuation hierarchy. On October 1, 2013, the trustee under the indenture governing Whiting's 2014 Notes provided notice to the holders of such notes that the Company elected to redeem all of the outstanding 2014 Notes on October 31, 2013. As a result of the redemption, Whiting will recognize an estimated $4.4 million loss on early extinguishment of debt during the fourth quarter of 2013, which will consist of a cash charge of $4.0 million related to the redemption premium on the 2014 Notes and a non-cash charge of $0.4 million related to the acceleration of unamortized debt issuance costs.

12

Table of Contents

In September 2010, the Company issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. The estimated fair value of these notes was $369.3 million as of September 30, 2013, based on quoted market prices for these debt securities, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

Issuance of Senior Notes. In September 2013, the Company issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400.0 million of 5.75% Senior Notes due March 2021 (collectively, the "Senior Notes"). The Company used the net proceeds from these issuances to repay all of the debt outstanding under its credit agreement and to fund its $260.0 million acquisition of Williston Basin assets discussed in the Acquisitions and Divestitures footnote. Additionally, the Company intends to use the remaining net issuance proceeds to redeem on October 31, 2013 all $250.0 million of its 7% Senior Subordinated Notes due February 2014, as well as for general corporate purposes including capital expenditures. The estimated fair values of the 2019 notes and the 2021 notes were $1,100.0 million and $1,227.0 million, respectively, as of September 30, 2013, based on quoted market prices for these debt securities, and such fair values are therefore designated as Level 1 within the valuation hierarchy.

The Senior Notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's secured indebtedness, which consists of Whiting Oil and Gas' credit agreement. The 2014 Notes and the 6.5% Senior Subordinated Notes due 2018 (the "2018 Notes" and collectively with the 2014 Notes, the "Senior Subordinated Notes") are also unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of the Senior Notes and Whiting Oil and Gas' credit agreement. The Company's obligations under the 2014 Notes are fully, unconditionally, jointly and severally guaranteed by the Company's 100%-owned subsidiaries, Whiting Oil and Gas and Whiting Programs, Inc. (the "2014 Guarantors"). Additionally, the Company's obligations under the 2018 Notes and the Senior Notes are fully, unconditionally, jointly and severally guaranteed by the Company's 100%-owned subsidiary, Whiting Oil and Gas (collectively with the 2014 Guarantors, the "Guarantors"). Any subsidiaries other than the 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 guarantor subsidiaries.

4. 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 Company follows FASB ASC Topic 410, Asset Retirement and Environmental Obligations, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The current portions at September 30, 2013 and December 31, 2012 were $11.7 million and $11.6 million, respectively, and are included in accrued liabilities and other. Revisions to the liability typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells. The following table provides a reconciliation of the Company's asset retirement obligations for the nine months ended September 30, 2013 (in thousands):

Asset retirement obligation at January 1, 2013	$97,818
Additional liability incurred	12,316
Revisions in estimated cash flows	3,515
Accretion expense	8,007
Obligations on sold properties	(3,555)
Liabilities settled	(7,312)
Asset retirement obligation at September 30, 2013	$110,789

Table of Contents

5. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and Whiting uses derivative instruments to manage its commodity price risk. Whiting follows FASB ASC Topic 815, Derivatives and Hedging, to account for its derivative financial instruments.

Commodity Derivative Contracts—Historically, prices received for crude oil and natural gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Whiting enters into derivative contracts, primarily costless collars and swaps, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility. Commodity derivative contracts are thereby used to ensure adequate cash flow to fund the Company's capital programs and to manage returns on acquisitions and drilling programs. Costless collars are designed to establish floor and ceiling prices on anticipated future oil or gas production, while swaps are designed to establish a fixed price for 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 Company does not enter into derivative contracts for speculative or trading purposes.

Whiting Derivatives. The table below details the Company's costless collar derivatives, including its proportionate share of Trust II derivatives, entered into to hedge forecasted crude oil production revenues, as of October 1, 2013.

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price for Crude Oil (per Bbl)
Collars	Oct – Dec 2013	493,020	\$ 48.35 - \$ 89.08
	Jan – Dec 2014	49,290	\$ 80.00 - \$122.50
Three-way collars(1)	Oct – Dec 2013	3,120,000	\$71.25 - \$85.63 - \$113.95
	Jan – Dec 2014	14,400,000	\$71.00 - \$85.00 - \$103.56
	Total	18,062,310	

(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.

In March 2013, Whiting entered into certain crude oil swap contracts in order to achieve more predictable cash flows and manage returns on certain oil and gas properties that the Company was considering for monetization. Accordingly, the acquisition of these swap contracts and cash receipts from settlements of these swap positions have been reflected as an investing activity in the statement of cash flows. On July 15, 2013, upon closing of the sale of the Postle Properties discussed in the Acquisitions and Divestitures footnote, these crude oil swaps were novated to the buyer. Cash settlements that do not relate to investing derivatives or that do not have a significant financing element are reflected as operating activities in the statement of cash flows.

Derivatives Conveyed to Whiting USA Trust II. In connection with the Company's conveyance in March 2012 of a term net profits interest to Trust II and related sale of 18,400,000 Trust II units to the public, the right to any future hedge payments made or received by Whiting on certain of its derivative contracts have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties, which results in third-party public holders of Trust II units receiving 90%, and Whiting retaining 10%, of the future economic results of commodity derivative contracts conveyed to Trust II. The relative ownership of the future economic results of such commodity derivatives is reflected in the tables below. No additional hedges are allowed to be placed on Trust II assets.

Table of Contents

The 10% portion of Trust II derivatives that Whiting has retained the economic rights to (and which are also included in the first derivative table above) are as follows:

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Oct – Dec 2013	13,020	\$80.00 - \$122.50
	Jan – Dec 2014	49,290	\$80.00 - \$122.50
	Total	62,310	

The 90% portion of Trust II derivative contracts of which Whiting has transferred the economic rights to third-party public holders of Trust II units (and which have not been reflected in the above tables) are as follows:

		Third-party Public Holders of Trust II Units	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Oct – Dec 2013	117,180	\$80.00 - \$122.50
	Jan – Dec 2014	443,610	\$80.00 - \$122.50
	Total	560,790	

Embedded Commodity Derivative Contract—In May 2011, Whiting entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in its enhanced oil recovery project that is being carried out at its North Ward Estes field in Texas. This contract contains a price adjustment clause that is linked to changes in NYMEX crude oil prices. The Company has determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to the host contract, and the Company has therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. As of September 30, 2013, the estimated fair value of the embedded derivative in this CO2 purchase contract was an asset of $31.3 million.

Although CO2 is not a commodity that is actively traded on a public exchange, the market price for CO2 generally fluctuates in tandem with increases or decreases in crude oil prices. When Whiting enters into a long-term CO2 purchase contract where the price of CO2 is fixed and does not adjust with changes in oil prices, the Company is exposed to the risk of paying higher than the market rate for CO2 in a climate of declining oil and CO2 prices. This in turn could have a negative impact on the project economics of the Company’s CO2 flood at North Ward Estes. As a result, the Company reduces its exposure to this risk by entering into certain CO2 purchase contracts which have prices that fluctuate along with changes in crude oil prices.

Table of Contents

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. The following tables summarize the effects of commodity derivatives instruments on the consolidated statements of income for the three and nine months ended September 30, 2013 and 2012 (in thousands):

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain (Loss) Reclassified from AOCI into Income (Effective Portion) (1) Nine Months Ended September 30, 2013	2012
Commodity contracts	Gain (loss) on hedging activities	$ (1,313)	$ 2,285

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain (Loss) Reclassified from AOCI into Income (Effective Portion) (1) Three Months Ended September 30, 2013	2012
Commodity contracts	Gain (loss) on hedging activities	$ (665)	$ 398

(1) Effective April 1, 2009, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. As a result, such mark-to-market values at March 31, 2009 were frozen in AOCI as of the de-designation date and are being reclassified into earnings as the original hedged transactions affect income.

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Nine Months Ended September 30, 2013	2012
Commodity contracts	Commodity derivative (gain) loss, net	$ 32,699	$ (59,701)
Embedded commodity contracts	Commodity derivative (gain) loss, net	(7,365)	(4,499)
Total		$ 25,334	$ (64,200)

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Three Months Ended September 30, 2013	2012
Commodity contracts	Commodity derivative (gain) loss, net	$ 22,293	$ 5,985
Embedded commodity contracts	Commodity derivative (gain) loss, net	1,976	436
Total		$ 24,269	$ 6,421

Offsetting of Derivative Assets and Liabilities. With each individual derivative counterparty, the Company typically has numerous hedge positions that span a several-month time period and that typically result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability amount at the end of each reporting period. The Company nets its 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 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):

Table of Contents

Not Designated as ASC 815 Hedges	Balance Sheet Classification	September 30, 2013(1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 26,439	$ (25,988)	$ 451
Commodity contracts	Other long-term assets	15,888	(14,947)	941
Embedded commodity contracts	Other long-term assets	31,264	-	31,264
Total derivative assets		$ 73,591	$ (40,935)	$ 32,656
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 45,969	$ (25,988)	$ 19,981
Embedded commodity contracts	Current derivative liabilities	183	-	183
Commodity contracts	Non-current derivative liabilities	15,446	(14,947)	499
Total derivative liabilities		$ 61,598	$ (40,935)	$ 20,663

Not Designated as ASC 815 Hedges	Balance Sheet Classification	December 31, 2012(1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 40,909	$ (31,437)	$ 9,472
Commodity contracts	Other long-term assets	4,053	(2,189)	1,864
Embedded commodity contracts	Other long-term assets	24,038	(323)	23,715
Total derivative assets		$ 69,000	$ (33,949)	$ 35,051
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 53,392	$ (31,437)	$ 21,955
Commodity contracts	Non-current derivative liabilities	3,867	(2,189)	1,678
Embedded commodity contracts	Non-current derivative liabilities	323	(323)	-
Total derivative liabilities		$ 57,582	$ (33,949)	$ 23,633

(1) Because counterparties to the Company's derivative contracts 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 the tables above.

Contingent Features in Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's 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.

6. 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:

Table of Contents

- 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.

The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2013 and December 31, 2012, 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, 2013
Financial Assets				
Commodity derivatives – current	$ -	$ 451	$ -	$ 451
Commodity derivatives – non-current	-	941	-	941
Embedded commodity derivatives – non-current	-	-	31,264	31,264
Total financial assets	$ -	$ 1,392	$ 31,264	$ 32,656
Financial Liabilities				
Commodity derivatives – current	$ -	$ 19,981	$ -	$ 19,981
Embedded commodity derivatives – current	-	183	-	183
Commodity derivatives – non-current	-	499	-	499
Total financial liabilities	$ -	$ 20,663	$ -	$ 20,663

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2012
Financial Assets				
Commodity derivatives – current	$ -	$ 9,472	$ -	$ 9,472
Commodity derivatives – non-current	-	1,864	-	1,864
	-	-	23,715	23,715

Embedded commodity derivatives – non-current								
Total financial assets	$	-	$	11,336	$	23,715	$	35,051
Financial Liabilities								
Commodity derivatives – current	$	-	$	21,955	$	-	$	21,955
Commodity derivatives – non-current		-		1,678		-		1,678
Total financial liabilities	$	-	$	23,633	$	-	$	23,633

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the tables above:

18

Table of Contents

Commodity Derivatives. Commodity derivative instruments consist of costless collars and swap contracts for crude oil. The Company's costless collars and swaps are valued based on an income approach. Both the option and swap models consider 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 counterparties' valuations to assess the reasonableness of its own valuations.

Embedded Commodity Derivatives. The embedded commodity derivative relates to a long-term CO2 purchase contract, which has a price adjustment clause that is linked to changes in NYMEX crude oil prices. Whiting has determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to its corresponding host contract, and the Company has therefore bifurcated this embedded pricing feature from the host contract and reflected it at fair value in its consolidated financial statements. This embedded commodity derivative is valued based on an income approach. The option model used in the valuation considers various assumptions, including quoted forward prices for commodities, LIBOR discount rates and either the Company's or the counterparty's nonperformance risk, as appropriate.

The assumptions used in the CO2 contract valuation include inputs that are both observable in the marketplace as well as unobservable during the term of the contract. With respect to forward prices for NYMEX crude oil where there is a lack of price transparency in certain future periods, such unobservable oil price inputs are significant to the CO2 contract valuation methodology, and the contract's fair value is therefore designated as Level 3 within the valuation hierarchy.

Level 3 Fair Value Measurements—A third-party valuation specialist is utilized on a quarterly basis to determine the fair value of the embedded commodity derivative instrument designated as Level 3. The Company reviews this valuation (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 (liabilities) designated as Level 3 in the valuation hierarchy for the three and nine months ended September 30, 2013 and 2012 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Fair value asset, beginning of period	$33,008	$17,678	$23,715	$12,980
Unrealized gains (losses) on embedded commodity derivative contracts included in earnings(1)	(1,744)	408	7,549	5,106
Transfers into (out of) Level 3	-	-	-	-
Fair value asset, end of period	$31,264	$18,086	$31,264	$18,086

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

Table of Contents

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

	Fair Value at September 30, 2013 (in thousands)	Valuation Technique	Unobservable Input	Range (per Bbl)
Embedded commodity derivative	$ 31,264	Option model	Future prices of NYMEX crude oil after December 31, 2021	$82.50 - $101.76

Sensitivity to Changes in Significant Unobservable Inputs. As presented in the table above, the significant unobservable inputs used in the fair value measurement of Whiting's embedded commodity derivative within its CO2 purchase contract are the future prices of NYMEX crude oil from January 2022 to December 2029. Significant increases (decreases) in these unobservable inputs in isolation would result in a significantly lower (higher) fair value asset measurement.

Nonrecurring Fair Value Measurements—The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including proved oil and gas property impairments. The Company did not recognize any impairment write-downs with respect to its proved oil and gas properties during the 2013 or 2012 reporting periods presented.

7. DEFERRED COMPENSATION

Production Participation Plan—The Company has a Production Participation Plan (the "Plan") in which all employees participate. On an annual basis, interests in oil and gas properties acquired, developed or sold during the year are allocated to the Plan as determined annually by the Compensation Committee of the Company's Board of Directors. Once allocated, the interests (not legally conveyed) are fixed. Interest allocations prior to 1995 consisted of 2%-3% overriding royalty interests. Interest allocations since 1995 have been 2%-5% of oil and gas sales less lease operating expenses and production taxes.

Payments of 100% of the year's Plan interests to employees and the vested percentages of former employees in the year's Plan interests are made annually in cash after year-end. Accrued compensation expense under the Plan for the nine months ended September 30, 2013 and 2012 amounted to $55.3 million and $37.1 million, respectively, charged to general and administrative expense and $5.7 million and $3.9 million, respectively, charged to exploration expense.

Employees vest in the Plan ratably at 20% per year over a five-year period. Pursuant to the terms of the Plan, (i) employees who terminate their employment with the Company are entitled to receive their vested allocation of future Plan year payments on an annual basis; (ii) employees will become fully vested at age 62, regardless of when their interests would otherwise vest; and (iii) any forfeitures inure to the benefit of the Company.

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At September 30, 2013, the Company used three-year average historical NYMEX prices of $94.40 for crude oil and $3.56 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control of the Company (as defined in the Plan), all employees fully vest and the Company would distribute to each Plan participant an amount, based upon the valuation method set forth in the Plan, in a lump sum payment twelve months after the date of termination or within one month after a change in control event. Based on current strip prices at September 30, 2013, if the Company elected to terminate the Plan or if a change of control event occurred, it is estimated that the fully vested lump sum cash payment to employees would approximate $203.3 million. This amount includes $27.0 million attributable to proved undeveloped oil and gas properties and $61.0 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in January 2014. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan.

Table of Contents

The following table presents changes in the Plan's estimated long-term liability (in thousands):

Long-term Production Participation Plan liability at January 1, 2013	$94,483
Change in liability for accretion, vesting, changes in estimates and new Plan year activity	62,346
Accrued compensation expense reflected as a current liability	(61,014)
Long-term Production Participation Plan liability at September 30, 2013	$95,815

Of the aggregate $61.0 million of accrued compensation under the Plan as of September 30, 2013, $23.9 million relates to the sale of the Postle Properties, which is further described in the Acquisitions and Divestitures footnote. This property sale also resulted in an offsetting benefit of $19.4 million realized related to the reduction in the Company's long-term Plan liability.

8. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

6.25% Convertible Perpetual Preferred Stock—In June 2009, the Company completed a public offering of 6.25% convertible perpetual preferred stock ("preferred stock"), selling 3,450,000 shares at a price of $100.00 per share. As a result of voluntary conversions and the Company exercising its right to mandatorily convert shares of preferred stock effective June 27, 2013, all 172,129 shares of preferred stock outstanding on March 31, 2013, were converted into 792,919 shares of common stock. As of September 30, 2013, no shares of preferred stock remained outstanding.

Each holder of the preferred stock was entitled to an annual dividend of $6.25 per share to be paid quarterly in cash, common stock or a combination thereof on March 15, June 15, September 15 and December 15, when and if such dividend had been declared by Whiting's board of directors.

Equity Incentive Plan—At the Company's 2013 Annual Meeting held on May 7, 2013, shareholders approved 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 5,300,000 shares of the Company's common stock. Upon shareholder approval of the 2013 Equity Plan, the 2003 Equity Plan and the authority to grant new awards under that plan were 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 after May 7, 2013 under the 2003 Equity Plan will 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 600,000 shares of common stock, stock appreciation rights relating to more than 600,000 shares of common stock, or more than 300,000 shares of restricted stock during any calendar year. As of September 30, 2013, 5,375,547 shares of common stock were available for grant under the 2013 Equity Plan.

Noncontrolling Interest—The noncontrolling interest represents an unrelated third party's 25% ownership interest in Sustainable Water Resources, LLC. The table below summarizes the activity for the equity attributable to the noncontrolling interest (in thousands):

	Nine Months Ended September 30,	
	2013	2012
Balance at January 1	$8,184	$8,274
Contributions from noncontrolling interest	-	-
Net income (loss)	(41)	(76)
Balance at September 30	$8,143	$8,198

9. 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, 2013 and 2012 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.

Table of Contents

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.

10. EARNINGS PER SHARE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Basic Earnings Per Share				
Numerator:				
Net income available to shareholders	$204,101	$83,134	$425,320	$332,486
Preferred stock dividends(1)	-	(269)	(494)	(808)
Net income available to common shareholders, basic	$204,101	$82,865	$424,826	$331,678
Denominator:				
Weighted average shares outstanding, basic	118,654	117,631	118,127	117,590
Diluted Earnings Per Share				
Numerator:				
Net income available to common shareholders, basic	$204,101	$82,865	$424,826	$331,678
Preferred stock dividends	-	269	538	808
Adjusted net income available to common shareholders, diluted	$204,101	$83,134	$425,364	$332,486
Denominator:				
Weighted average shares outstanding, basic	118,654	117,631	118,127	117,590
Restricted stock and stock options	853	499	888	584
Convertible perpetual preferred stock		794	496	794
Weighted average shares outstanding, diluted	119,507	118,924	119,511	118,968
Earnings per common share, basic	$1.72	$0.70	$3.60	$2.82
Earnings per common share, diluted	$1.71	$0.70	$3.56	$2.79

(1) For the nine months ended September 30, 2013, amount includes a decrease of $0.04 million in preferred stock dividends for preferred stock dividends accumulated.

For the three months ended September 30, 2013, the diluted earnings per share calculation excludes (i) the dilutive effect of 170,256 incremental shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2013, and (ii) the dilutive effect of 8,720 common shares for stock options that were out-of-the-money. For the three months ended September 30, 2012, the diluted earnings per share calculation excludes (i) the dilutive effect of 152,079 incremental shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2012, and (ii) the anti-dilutive effect of 23,320 common shares for stock options that were out-of-the-money.

Table of Contents

For the nine months ended September 30, 2013, the diluted earnings per share calculation excludes (i) the dilutive effect of 176,775 incremental shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2013, and (ii) the dilutive effect of 4,754 common shares for stock options that were out-of-the-money. For the nine months ended September 30, 2012, the diluted earnings per share calculation excludes (i) the dilutive effect of 135,381 incremental shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2012, and (ii) the anti-dilutive effect of 9,920 common shares for stock options that were out-of-the-money.

11. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In December 2011, the FASB issued Accounting Standards Update No. 2011-11, Balance Sheet: Disclosures about Offsetting Assets and Liabilities ("ASU 2011-11"). The objective of ASU 2011-11 is to require an entity to provide enhanced disclosures that will enable users of its financial statements to evaluate the effect or potential effect of netting arrangements on an entity's financial position. In January 2013, the FASB issued Accounting Standards Update No. 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities ("ASU 2013-01"), which clarifies that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with FASB ASC Topic 815, Derivatives and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities lending transactions that are either offset in accordance with FASB ASC Section 210-20-45 or Section 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. ASU 2011-11 and ASU 2013-01 are effective for interim and annual reporting periods beginning on or after January 1, 2013 and should be applied retrospectively. The Company adopted ASU 2011-11 and ASU 2013-01 effective January 1, 2013, which did not have an impact on the Company's consolidated financial statements other than additional disclosures.

In July 2012, the FASB issued Accounting Standards Update No. 2012-02, Intangibles – Goodwill and Other – Testing Indefinite-Lived Intangible Assets for Impairment ("ASU 2012-02"). The objective of ASU 2012-02 is to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by permitting an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired, as a basis for determining whether it is necessary to perform a quantitative impairment test. ASU 2012-02 is effective for interim and annual reporting periods beginning after September 15, 2012. The Company adopted ASU 2012-02 effective January 1, 2013, which did not have an impact on the Company's consolidated financial statements.

In February 2013, the FASB issued Accounting Standards Update No. 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income ("ASU 2013-02"). The objective of ASU 2013-02 is to improve the reporting of reclassifications out of AOCI by requiring an entity to report the effect of significant reclassifications out of AOCI on the respective line items in net income if the amount being reclassified is required under GAAP to be reclassified in its entirety to net income. For other amounts that are not required under GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures required under GAAP that provide additional detail about those amounts. ASU 2013-02 is effective for interim and annual reporting periods beginning after December 15, 2012. The Company adopted ASU 2013-02 effective January 1, 2013, which did not have a significant impact on the Company's consolidated financial statements.

In February 2013, the FASB issued Accounting Standards Update No. 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date ("ASU 2013-04"). The objective of ASU 2013-04 is to provide guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU 2013-04 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

23

Table of Contents

In July 2013, the FASB issued Accounting Standards Update No. 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists ("ASU 2013-11"). The objective of ASU 2013-11 is to provide guidance on financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. ASU 2013-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this standard will not have an impact on the Company's consolidated financial statements, other than insignificant balance sheet reclassifications.

12. SUBSEQUENT EVENT

On October 7, 2013, Whiting entered into a purchase and sale agreement with an undisclosed third party to sell approximately 45,000 gross (32,200 net) acres, including its interests in certain producing oil and gas wells and undeveloped acreage, located in its Big Tex prospect in the Delaware Basin for a cash purchase price of $150.1 million, subject to normal closing and post-closing adjustments. Of the total net acres sold, approximately 30,800 net acres are located in Pecos County, Texas, and approximately 1,400 net acres are located in Reeves County, Texas. The effective date of the transaction is October 1, 2013, and it is expected to close by October 31, 2013. The producing properties had estimated proved reserves of 1.1 MMBOE as of December 31, 2012, representing 0.3% of Whiting's proved reserves as of that date, and generated 0.2 MBOE/d of Whiting's third quarter 2013 average daily net production.

Table of Contents

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 Whiti Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas 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 exploration, development, acquisition and production activities primarily in the Rocky Mountains, Permian Basin, Michigan, Gulf Coast and Mid-Continent regions of the United States. Prior to 2006, we generally emphasized the acquisition of properties that increased our production levels and provided upside potential through further development. Since 2006, we have focused primarily on organic drilling activity and on the development of previously acquired properties, specifically on projects that we believe provide the opportunity for repeatable successes and production growth. We believe the combination of acquisitions, subsequent development and organic drilling provides us with a broad set of growth alternatives and allows us to direct our capital resources to what we believe to be the most advantageous investments.

As demonstrated by our recent capital expenditure programs, we are increasingly focused on a balanced exploration and development program, while continuing to selectively pursue acquisitions that complement our existing core properties. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- allocating a portion of our exploration and development budget to leasing and exploring prospect areas;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows; and
- seeking property acquisitions that complement our core areas.

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that established a presence in a new area of interest or that have complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis.

We continually evaluate our current 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.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. 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 2011:

Table of Contents

	2011				2012				2013		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Crude Oil	$94.25	$102.55	$89.81	$94.02	$102.94	$93.51	$92.19	$88.20	$94.34	$94.23	$105.82
Natural Gas	$4.10	$4.32	$4.20	$3.54	$2.72	$2.21	$2.81	$3.41	$3.34	$4.10	$3.58

Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and gas reserves. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil and gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders and which is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil and natural gas prices may result in significant non-cash, mark-to-market losses being incurred on our commodity-based derivatives, which may in turn cause us to experience net losses.

2013 Highlights and Future Considerations

Operational Highlights.

Sanish and Parshall. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish and Parshall fields averaged 36.8 MBOE/d for the third quarter of 2013, representing a 1% increase from 36.3 MBOE/d in the second quarter of 2013. As of September 30, 2013, we had five drilling rigs active in the Sanish field. We also initiated higher density pilot programs in the Sanish and Parshall fields in the second quarter of 2013, and we anticipate a production response in the fourth quarter of 2013.

Lewis & Clark/Pronghorn. Our Lewis & Clark/Pronghorn prospects are located primarily in the Stark and Billings counties of North Dakota and run along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Pronghorn Sand and Three Forks formations (Middle Bakken and Lower Bakken Shale is absent). Net production in the Lewis & Clark/Pronghorn prospects averaged 14.2 MBOE/d in the third quarter of 2013, representing a 6% increase from 13.3 MBOE/d in the second quarter of 2013. As of September 30, 2013, we had six drilling rigs operating in the Pronghorn prospect, five of which are utilizing pad drilling, drilling two or three wells from each pad. We are realizing cost efficiencies with the use of multi-well pads in the drilling and completion of wells in the Pronghorn prospect. Additionally, we are testing our new completion design in the Lewis & Clark/Pronghorn prospects utilizing cemented liners and plug-and-perf technology and are encouraged by the results.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which has a processing capacity of 35 MMcf/d and which primarily processes production from the Pronghorn area. Currently, there is inlet compression in place to process 35 MMcf/d, and as of September 30, 2013 the plant was processing 20 MMcf/d. In November 2012, we began connecting other operators' wells to the plant, and we added inlet compression during 2013 in order to fully utilize the plant's processing capability. During the second quarter of 2013, we installed fractionation equipment to convert NGLs into propane and butane, which end products can then be sold locally for higher realized prices. In May 2012, we sold a 50% ownership interest in the plant, gathering systems and related facilities. We retained a 50% ownership interest and will continue to operate the Belfield plant and facilities. Additionally, we completed construction on an oil terminal and a seven-mile oil transmission line to allow for the delivery of oil production from the Pronghorn prospect into the Bridger Four Bears and Bakken Link oil transmission systems. We expect the use of this terminal to reduce our transportation costs per barrel and increase our returns on the development of this prospect.

Table of Contents

Hidden Bench/Tarpon. Our Hidden Bench and Tarpon prospects in McKenzie County, North Dakota target the Bakken and Three Forks formations. In the third quarter of 2013, net production from the Hidden Bench/Tarpon prospects averaged 10.2 MBOE/d, representing a 73% increase from 5.9 MBOE/d in the second quarter of 2013. We have also implemented our new completion design at our Hidden Bench prospect, utilizing cemented liners and higher sand volumes, which has generated positive results. In the Tarpon prospect, we have drilled six productive wells as of September 30, 2013. We had previously planned to drill most of the remaining Tarpon development wells during 2013 but were delayed by federal drilling permit requirements for these wells. We anticipate that we will be able to resume drilling in 2014, and we have begun permitting additional wells for 2014.

Missouri Breaks Prospect. Our Missouri Breaks prospect, which is located in Richland County, Montana and McKenzie County, North Dakota targets the Middle Bakken formation. In the third quarter of 2013, net production from the Missouri Breaks prospect averaged 2.9 MBOE/d, representing an 8% increase from 2.7 MBOE/d in the second quarter of 2013. We implemented our new completion design at this prospect, utilizing cemented liners and higher sand volumes, and the new design appears to improve production rates. We have drilled successful wells on the western, eastern and southern portions of our acreage in this area.

Big Island Prospect. Our Big Island prospect, which is located in Golden Valley County, North Dakota and Wibaux County, Montana, targets the Red River formation. We are using 3-D seismic interpretations to identify Red River drilling locations at our Big Island prospect. We plan to use a horizontal well to test the Lower Red River “D” zone in 2013.

North Ward Estes. The North Ward Estes field is located in the Ward and Winkler counties of Texas, and we continue to have significant development and related infrastructure activity in this field since we acquired it in 2005. Our activity at North Ward Estes to date has resulted in substantial reserve additions and production increases, and our expansion of the CO2 flood in this area continues to generate positive results.

North Ward Estes has been responding positively to the water and CO2 floods that we initiated in May 2007. We are currently injecting CO2 in one of the largest phases of our eight-phase project at North Ward Estes, and several of the phases of the CO2 flood are continuing to respond. Net production from North Ward Estes averaged 9.6 MBOE/d for the third quarter of 2013, which represents a 4% increase from 9.3 MBOE/d in the second quarter of 2013. As of September 30, 2013, we were injecting approximately 365 MMcf/d of CO2 into the field, over half of which is recycled.

Big Tex. Our Big Tex prospect in Pecos, Reeves and Ward counties, Texas targets the Brushy Canyon, Bone Spring and Wolfcamp horizons of the Delaware Basin. In late 2012, we completed a well utilizing a cemented liner and a plug-and-perf completion technique. Based on the performance of this well, we plan to implement this completion strategy on the horizontal wells drilled in this prospect during 2013. In October 2013, we entered into a purchase and sale agreement with an undisclosed third party to sell approximately 45,000 gross (32,200 net) acres, including interests in certain producing oil and gas wells and undeveloped acreage, located in our Big Tex prospect, as discussed below under “Acquisition and Divestiture Highlights.”

Redtail. Our Redtail prospect in the Denver Julesberg Basin in Weld County, Colorado targets the Niobrara formation. In September 2013, we completed the acquisition of approximately 47,800 gross (32,100 net) acres at our Redtail prospect, including interests in one producing well and undeveloped acreage. Our development plan at Redtail includes drilling up to eight Niobrara “B” wells per spacing unit and eight Niobrara “A” wells per spacing unit. The associated gas produced with the Niobrara oil must be processed before being sold, and we have therefore initiated the construction of our own gas processing plant in Weld County, Colorado. The plant’s inlet capacity will be 15 MMcf/d. The air permit for the plant was filed with the Colorado Department of Public Health and Environment in November 2012, and we have ordered the major equipment necessary to construct this plant. We anticipate having the plant online in early 2014. As of September 30, 2013, we had two drilling rigs operating in this area, and we plan to add a third rig in November 2013. We also implemented a new completion design in this prospect, resulting in strong consistent results.

Table of Contents

Financing Highlights. In September 2013, we entered into an amendment to our existing credit agreement to permit us to issue up to $2.3 billion of senior notes without a reduction in our borrowing base.

On September 12, 2013, we issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021. On September 26, 2013, we issued at 101% of par $400.0 million of 5.75% Senior Notes due March 2021. We used the net proceeds from these issuances to repay all of the debt outstanding under our credit agreement and to fund our $260.0 million acquisition of Williston Basin assets. Additionally, we intend to use the remaining net issuance proceeds to redeem on October 31, 2013 all $250.0 million aggregate principal amount of our outstanding 7% Senior Subordinated Notes due February 2014, as well as for general corporate purposes including capital expenditures.

Upon closing of the sale of the Postle Properties discussed below, our credit agreement borrowing base and aggregate commitments decreased from $2.5 billion to $2.15 billion. In addition, upon completion of the first Senior Note offering on September 12, 2013, we voluntarily reduced the aggregate commitments under our credit agreement from $2.15 billion to $1.2 billion.

Acquisition and Divestiture Highlights. In September 2013, we completed the acquisition of approximately 39,300 gross (17,300 net) acres, including interests in 121 producing oil and gas wells and undeveloped acreage, in the Williston Basin located in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an aggregate unadjusted purchase price of $260.0 million.

In July 2013, we completed the sale of our interests in certain oil and gas producing properties located in our enhanced oil recovery projects in the Postle and Northeast Hardesty fields in Texas County, Oklahoma, including the related Dry Trail plant gathering and processing facility, oil delivery pipeline, our entire 60% interest in the Transpetco CO2 pipeline, crude oil swap contracts and certain other related assets and liabilities (collectively the “Postle Properties”), effective April 1, 2013, for a cash purchase price of $816.5 million after selling costs and post-closing adjustments, resulting in a pre-tax gain on sale of $116.4 million. We used the net proceeds from this sale to repay a portion of the debt outstanding under our credit agreement. The Postle Properties consisted of estimated proved reserves of 45.1 MMBOE as of December 31, 2012, representing 11.9% of our proved reserves as of that date, and generated 8% (or 7.6 MBOE/d) of our June 2013 average daily net production.

In October 2013, we entered into a purchase and sale agreement with an undisclosed third party to sell approximately 45,000 gross (32,200 net) acres, including our interests in certain producing oil and gas wells and undeveloped acreage, located in our Big Tex prospect in the Delaware Basin for a cash purchase price of $150.1 million, subject to normal closing and post-closing adjustments. Of the total net acres sold, approximately 30,800 net acres are located in Pecos County, Texas, and approximately 1,400 net acres are located in Reeves County, Texas. The effective date of the transaction is October 1, 2013, and it is expected to close by October 31, 2013. The producing properties had estimated proved reserves of 1.1 MMBOE as of December 31, 2012, representing 0.3% of our proved reserves as of that date, and generated 0.2 MBOE/d of our third quarter 2013 average daily net production.

Table of Contents

Results of Operations

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

	Nine Months Ended September 30, 2013	2012
Net production:		
Oil (MMBbl)	19.7	17.0
NGLs (MMBbl)	2.1	2.1
Natural gas (Bcf)	19.8	19.3
Total production (MMBOE)	25.1	22.3
Net sales (in millions):		
Oil (1)	$1,806.1	$1,429.5
NGLs	80.3	78.2
Natural gas (1)	77.1	64.9
Total oil, NGL and natural gas sales	$1,963.5	$1,572.6
Average sales prices:		
Oil (per Bbl)	$91.74	$83.99
Effect of oil hedges on average price (per Bbl)	(1.31)	(1.55)
Oil net of hedging (per Bbl)	$90.43	$82.44
Average NYMEX price (per Bbl)	$98.17	$96.20
NGLs (per Bbl)	$38.78	$38.06
Natural gas (per Mcf)	$3.90	$3.36
Effect of natural gas hedges on average price (per Mcf)	-	0.06
Natural gas net of hedging (per Mcf)	$3.90	$3.42
Average NYMEX price (per Mcf)	$3.67	$2.58
Cost and expenses (per BOE):		
Lease operating expenses	$12.54	$12.48
Production taxes	$6.64	$5.78
Depreciation, depletion and amortization expense	$25.71	$22.26
General and administrative expenses	$4.33	$3.80

(1) Before consideration of hedging transactions.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $390.9 million to $1,963.5 million when comparing the first nine months of 2013 to the same period in 2012. Sales revenue is a function of oil and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 16%, and our natural gas sales volumes increased 2% between periods, while our NGL sales volumes remained consistent between periods. The oil volume increase resulted primarily from drilling success at our Hidden Bench/Tarpon prospects, Sanish and Parshall fields, Lewis & Clark/Pronghorn prospects, Missouri Breaks prospect and our Redtail prospect. During the first nine months of 2013, oil production from our Hidden Bench/Tarpon prospects increased 995 MBbl, oil production from our Sanish and Parshall fields increased 675 MBbl, oil production from our Lewis & Clark/Pronghorn prospects increased 660 MBbl, oil production from our Missouri Breaks prospect increased 585 MBbl, and oil production from our Redtail prospect increased 395 MBbl over the same period in 2012. These production increases were partially offset by the sale of the Postle Properties in July 2013 and the Whiting USA Trust II (“Trust II”) divestiture in March 2012, which divestitures negatively impacted oil production in the first nine months of 2013 by 635 MBbl and 295 MBbl, respectively. The gas volume increase between periods was primarily the result of new wells drilled and completed during the past twelve months, which caused increases in associated gas production of 1,105 MMcf at our Sanish and Parshall fields and 785 MMcf at our Hidden Bench/Tarpon prospects. These gas volume increases were largely offset by normal field production decline across several of our areas, the most notable of which was our Flat Rock field where production volumes decreased 940 MMcf when comparing the first nine months of 2013 to production during the first nine months of 2012. In addition, the Trust II divestiture in March 2012 negatively impacted gas production in the first nine months of 2013 by 545 MMcf.

Table of Contents

In addition to the above crude oil and natural gas production-related increases in net revenue were increases in the average sales prices realized for oil, NGLs and natural gas in the first nine months of 2013 compared to the first nine months of 2012. Our average price for oil before the effects of hedging increased 9%, our average price for NGLs increased 2% between periods, and our average price for natural gas before the effects of hedging increased 16% between periods.

Gain (Loss) on Sale of Properties. During the first nine months of 2013, we sold our interest in the Postle Properties for net proceeds of $816.5 million in cash, which resulted in a pre-tax gain on sale of $116.4 million. There were no other property divestitures resulting in a significant gain or loss on sale during the nine months ended September 30, 2013 or during the nine months ended September 30, 2012.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during the first nine months of 2013 were $314.1 million, a $35.9 million increase over the same period in 2012. Higher LOE in 2013 were primarily related to a $38.4 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months. This increase was partially offset by a decrease in well workover activity from $65.0 million in the first nine months of 2012 to $62.5 million in the first nine months of 2013.

Our lease operating expenses on a BOE basis also increased during the first nine months of 2013. LOE per BOE amounted to $12.54 during the first nine months of 2013, which was up from $12.48 per BOE for the first nine months of 2012. This increase was mainly due to the higher costs of oil field goods and services in 2013, as discussed above, partially offset by higher overall production volumes between periods.

Production Taxes. Our production taxes during the first nine months of 2013 were $166.2 million, a $37.3 million increase over the same period in 2012, 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 was 8.5% and 8.2% for the first nine months of 2013 and 2012, respectively. Our production tax rate of 8.5% for the first nine months of 2013 was greater than the rate for the same period in 2012 due to successful wells completed during the past twelve months in North Dakota, which has an 11.5% severance tax rate.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense increased $147.8 million in 2013 as compared to the first nine months of 2012. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2013	2012
Depletion	$633,077	$488,333
Depreciation	3,051	2,624
Accretion of asset retirement obligations	8,007	5,339
Total	$644,135	$496,296

DD&A increased in the first nine months of 2013 primarily due to $144.7 million in higher depletion expense between periods. Of this increase, $74.9 million related to a higher depletion rate between periods and $69.8 million related to the increase in our overall production volumes during the first nine months of 2013. On a BOE basis, our overall DD&A rate of $25.71 for the first nine months of 2013 was 15% higher than the rate of $22.26 for the same period in 2012 due to $2,173.0 million in drilling and development expenditures during the past twelve months, which were partially offset by reserve additions during this same time period.

30

Table of Contents

Exploration and Impairment Costs. Our exploration and impairment costs increased $48.4 million in the first nine months of 2013 as compared to the same period in 2012. The components of our exploration and impairment costs were as follows (in thousands):

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Exploration	$71,635	$33,592
Impairment	56,130	45,770
Total	$127,765	$79,362

Exploration costs increased $38.0 million during the first nine months of 2013 as compared to the same period in 2012 primarily due to higher exploratory dry hole costs, an increase in geological and geophysical ("G&G") activity, higher delay lease rentals paid and an increase in geology-related general and administrative expenses. Exploratory dry hole costs for the first nine months of 2013 totaled $21.2 million, primarily related to five exploratory dry holes drilled in the Rocky Mountains and Permian Basin regions during the second and third quarters of 2013. During the nine months ended September 30, 2012, on the other hand, we drilled only one exploratory dry hole in the Rocky Mountains region totaling $2.1 million. G&G costs, such as seismic studies, amounted to $23.5 million during the first nine months of 2013 as compared to $13.3 million during the first nine months of 2012. Delay lease rentals increased $4.6 million between periods, while geology-related general and administrative expenses increased $4.2 million.

Impairment expense in the first nine months of 2013 and 2012 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $54.8 million in the first nine months of 2013 as compared to $40.2 million in the first nine months of 2012. In addition, acreage costs of $5.6 million were written-off to impairment expense in the first nine months of 2012 for leases that had reached their expiration dates but where no wells had been drilled on such acreage.

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

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
General and administrative expenses	$192,056	$151,329
Reimbursements and allocations	(83,590)	(66,718)
General and administrative expense, net	$108,466	$84,611

General and administrative expense before reimbursements and allocations ("G&A") increased $40.7 million during the first nine months of 2013 as compared to the same period in 2012 primarily due to higher employee compensation and an increase in accrued Plan distributions. Employee compensation increased $21.4 million in the first nine months of 2013 as compared to the same period in 2012 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. Accrued distributions under the Plan increased $18.1 million between periods primarily due to a one-time charge under the Plan of $21.7 million for the sale of the Postle Properties in the third quarter of 2013. This increase was partially offset by higher accrued Plan distributions at September 30, 2012 due to the Trust II net profits interest divestiture in March 2012, which in turn triggered $8.6 million of distributions payable to Plan participants as a result of this monetization of Plan assets.

The increase in reimbursements and allocations for the first nine months of 2013 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties. Our general and administrative expenses as a percentage of oil, NGL and natural gas sales remained consistent for the first nine months of 2013 and 2012 at about 5%.

Table of Contents

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

	Nine Months Ended September 30,	
	2013	2012
Senior Notes and Senior Subordinated Notes	$35,838	$30,188
Credit agreement	26,731	19,958
Amortization of debt issue costs and debt premium	7,800	7,051
Other	63	104
Capitalized interest	(853)	(2,206)
Total	$69,579	$55,095

The increase in interest expense of $14.5 million between periods was mainly attributable to a $6.8 million increase in the amount of interest incurred on our credit agreement during the first nine months of 2013 as compared to the first nine months of 2012. Our credit agreement interest was higher in 2013 due to a greater amount of borrowings outstanding under this facility. In addition, interest on our notes increased $5.7 million for the first nine months of 2013 as compared to the same period in 2012 due to our September 2013 issuance of $1,100.0 million of 5% Senior Notes due 2019 and $1,200.0 million of 5.75% Senior Notes due 2021. Our weighted average debt outstanding during the first nine months of 2013 was $2,104.2 million versus $1,502.0 million for the first nine months of 2012. Our weighted average effective cash interest rate was 4.0% during the first nine months of 2013 compared to 4.5% during the first nine months of 2012.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity 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 from the counterparty. Commodity derivative (gain) loss, net amounted to a loss of $25.3 million for the nine months ended September 30, 2013 due to the downward shift in the futures curve of forecasted commodity prices (“forward price curve”) for crude oil from January 1, 2013 to September 30, 2013. Commodity derivative (gain) loss, net for the nine months ended September 30, 2012, however, resulted in a gain of $64.2 million due to a significant upward shift in the same forward price curve from January 1, 2012 to September 30, 2012.

Income Tax Expense. Income tax expense totaled $225.7 million for the first nine months of 2013 as compared to $199.5 million of income tax for the first nine months of 2012, an increase of $26.2 million that was mainly related to $119.1 million in higher pre-tax income between periods.

Our effective tax rates for the periods ending September 30, 2013 and 2012 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate decreased from 37.5% for the first nine months of 2012 to 34.7% for the first nine months of 2013. This decrease in rate is primarily attributable to state tax credits and a reduction to the North Dakota corporate tax rate, which created a one-time benefit during the first nine months of 2013.

Table of Contents

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

	Three Months Ended September 30, 2013	2012
Net production:		
Oil (MMBbl)	6.7	5.9
NGLs (MMBbl)	0.7	0.7
Natural gas (Bcf)	6.8	6.3
Total production (MMBOE)	8.5	7.6
Net sales (in millions):		
Oil (1)	$658.0	$478.6
NGLs	23.8	21.1
Natural gas (1)	24.7	21.5
Total oil, NGL and natural gas sales	$706.5	$521.2
Average sales prices:		
Oil (per Bbl)	$97.69	$81.66
Effect of oil hedges on average price (per Bbl)	(2.01)	(0.80)
Oil net of hedging (per Bbl)	$95.68	$80.86
Average NYMEX price (per Bbl)	$105.82	$92.19
NGLs (per Bbl)	$35.78	$30.77
Natural gas (per Mcf)	$3.64	$3.39
Effect of natural gas hedges on average price (per Mcf)	-	0.05
Natural gas net of hedging (per Mcf)	$3.64	$3.44
Average NYMEX price (per Mcf)	$3.58	$2.81
Cost and expenses (per BOE):		
Lease operating expenses	$12.79	$12.35
Production taxes	$7.17	$5.73
Depreciation, depletion and amortization expense	$25.73	$23.63
General and administrative expenses	$5.90	$3.29

(1) Before consideration of hedging transactions.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $185.3 million to $706.5 million when comparing the third quarter of 2013 to the same period in 2012. Sales revenue is a function of oil and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 15%, and our natural gas sales volumes increased 7% between periods, while our NGL sales volumes remained consistent between periods. The oil volume increase resulted primarily from drilling success at our Hidden Bench/Tarpon prospects, Sanish and Parshall fields, Missouri Breaks prospect, Redtail prospect and our Lewis & Clark/Pronghorn prospects. During the third quarter of 2013, oil production from our Hidden Bench/Tarpon prospects increased 600 MBbl, oil production from our Sanish and Parshall fields increased 205 MBbl, oil production from our Missouri Breaks prospect increased 200 MBbl, oil production from our Redtail prospect increased 175 MBbl, and oil production from our Lewis & Clark/Pronghorn prospects increased 150 MBbl over the same period in 2012. These production increases were partially offset by the sale of the Postle Properties in July 2013, which negatively impacted oil production in the third quarter of 2013 by 540 MBbl. The gas volume increase between periods was primarily the result of new oil wells drilled and completed during the past twelve months, which caused increases in associated gas production of 430 MMcf at our Hidden Bench/Tarpon prospects and 295 MMcf at our Sanish and Parshall fields. These gas volume increases were partially offset by normal field production decline across several of our areas, the most notable of which was our Flat Rock field where production volumes decreased 290 MMcf when comparing the third quarter of 2013 to third quarter 2012 production.

Table of Contents

In addition to the above crude oil and natural gas production-related increases in net revenue were increases in the average sales prices realized for oil, NGLs and natural gas in the third quarter of 2013 compared to the third quarter of 2012. Our average price for oil before the effects of hedging increased 20%, our average price for NGLs increased 16%, and our average price for natural gas before the effects of hedging increased 7% between periods.

Gain (Loss) on Sale of Properties. During the third quarter of 2013, we sold our interest in the Postle Properties for net proceeds of $816.5 million in cash, which resulted in a pre-tax gain on sale of $116.4 million. There were no other property divestitures resulting in a significant gain or loss on sale during the three months ended September 30, 2013 or during the three months ended September 30, 2012.

Lease Operating Expenses. Our LOE during the third quarter of 2013 were $109.1 million, a $15.2 million increase over the same period in 2012. Higher LOE in 2013 were primarily related to a $12.4 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months, as well as a higher level of workover activity. Workovers increased from $18.9 million in the third quarter of 2012 to $21.7 million in the third quarter of 2013, primarily due to a higher number of well workovers being conducted at our CO2 project at North Ward Estes, partially offset by a lower number of well workovers at our Postle field which we sold in July 2013.

Our lease operating expenses on a BOE basis also increased during the third quarter of 2013. LOE per BOE amounted to $12.79 during the third quarter of 2013, which was up from $12.35 per BOE during the third quarter of 2012. This increase was mainly due to higher costs of oil field goods and services and an increase in well workover costs in 2013, as discussed above, which were partially offset by higher overall production volumes between periods.

Production Taxes. Our production taxes during the third quarter of 2013 were $61.1 million, a $17.6 million increase over the same period in 2012, 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 was 8.7% and 8.4% for the third quarter of 2013 and 2012, respectively. Our production tax rate of 8.7% for the third quarter of 2013 was greater than the rate for the same period in 2012 due to successful wells completed during the past twelve months in North Dakota, which has an 11.5% severance tax rate.

Depreciation, Depletion and Amortization. Our DD&A expense increased $39.9 million in 2013 as compared to the third quarter of 2012. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30,	
	2013	2012
Depletion	$216,174	$176,917
Depreciation	968	966
Accretion of asset retirement obligations	2,388	1,704
Total	$219,530	$179,587

DD&A increased in the third quarter of 2013 primarily due to $39.3 million in higher depletion expense between periods. Of this increase, $15.7 million related to a higher depletion rate between periods and $23.6 million related to the increase in our overall production volumes during the third quarter of 2013. On a BOE basis, our overall DD&A rate of $25.73 for the third quarter of 2013 was 9% higher than the rate of $23.63 for the same period in 2012 due to $2,173.0 million in drilling and development expenditures during the past twelve months, which were partially offset by reserve additions during this same time period.

Table of Contents

Exploration and Impairment Costs. Our exploration and impairment costs increased $23.2 million in the third quarter of 2013 as compared to the same period in 2012. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended September 30,	
	2013	2012
Exploration	$28,426	$10,338
Impairment	18,666	13,544
Total	$47,092	$23,882

Exploration costs increased $18.1 million during the third quarter of 2013 as compared to the same period in 2012 primarily due to higher exploratory dry hole costs and higher delay lease rentals paid. During the third quarter of 2013, we drilled three exploratory dry holes in the Rocky Mountains region totaling $9.5 million. During the third quarter of 2012, on the other hand, we only drilled one exploratory dry hole in the Rocky Mountains region totaling $1.9 million. Delay lease rentals increased $4.3 million between periods.

Impairment expense in the third quarter of 2013 and 2012 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $18.4 million in the third quarter of 2013 as compared to $13.4 million in the third quarter of 2012.

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

	Three Months Ended September 30,	
	2013	2012
General and administrative expenses	$79,554	$49,111
Reimbursements and allocations	(29,186)	(24,077)
General and administrative expense, net	$50,368	$25,034

General and administrative expense before reimbursements and allocations increased $30.4 million during the third quarter of 2013 as compared to the same period in 2012 primarily due to an increase in accrued Plan distributions and higher employee compensation. Accrued distributions under the Plan increased $24.5 million between periods primarily due to a one-time charge of $21.7 million under the Plan for the sale of the Postle Properties during the third quarter of 2013. Employee compensation increased $6.0 million in the third quarter of 2013 as compared to the same period in 2012 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods.

The increase in reimbursements and allocations for the third quarter of 2013 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties. Our general and administrative expenses as a percentage of oil, NGL and natural gas sales increased from 5% in the third quarter of 2012 to 7% in the third quarter of 2013, and this increase was mainly attributable to the one-time charge of $21.7 million relating to the Postle Properties sale, as discussed above.

Table of Contents

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

	Three Months Ended September 30,	
	2013	2012
Senior Notes and Senior Subordinated Notes	$15,713	$10,063
Credit agreement	6,650	7,040
Amortization of debt issue costs and debt premium	2,849	2,360
Other	27	46
Capitalized interest	(251)	(775)
Total	$24,988	$18,734

The increase in interest expense of $6.3 million between periods was mainly attributable to a $5.7 million increase in the amount of interest incurred on our notes during the third quarter of 2013 as compared to the third quarter of 2012. Interest on our notes was higher in 2013 due to our September 2013 issuance of $1,100.0 million of 5% Senior Notes due 2019 and $1,200.0 million of 5.75% Senior Notes due 2021. Our weighted average debt outstanding during the third quarter of 2013 was $1,959.9 million versus $1,522.7 million for the third quarter of 2012. Our weighted average effective cash interest rate was 4.6% during the third quarter of 2013 compared to 4.5% during the third quarter of 2012.

Commodity Derivative (Gain) Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity 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 from the counterparty. Commodity derivative (gain) loss, net amounted to a loss of $24.3 million for the three months ended September 30, 2013 due to the downward shift in the forward price curve for NYMEX crude oil from July 1, 2013 to September 30, 2013. Commodity derivative (gain) loss, net for the three months ended September 30, 2012 amounted to a loss of only $6.4 million, however, due to a less significant downward shift in the same forward price curve from July 1, 2012 to September 30, 2012.

Income Tax Expense. Income tax expense totaled $101.2 million for the third quarter of 2013 as compared to $50.1 million of income tax for the third quarter of 2012, an increase of $51.1 million that was mainly related to $172.1 million in higher pre-tax income between periods.

Our effective tax rates for the periods ending September 30, 2013 and 2012 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate decreased from 37.6% for the third quarter of 2012 to 33.1% for the third quarter of 2013. This decrease in rate is primarily attributable to state tax credits which created a one-time benefit during the three months ended September 30, 2013.

Liquidity and Capital Resources

Overview. At September 30, 2013, our debt to total capitalization ratio was 42.8%, we had $1,025.6 million of cash on hand and $3,881.9 million of equity. At December 31, 2012, our debt to total capitalization ratio was 34.3%, we had $44.8 million of cash on hand and $3,445.0 million of equity. During the first nine months of 2013, we generated $1,254.1 million of cash provided by operating activities, an increase of $236.2 million over the same period in 2012. Cash provided by operating activities increased primarily due to higher realized sales prices for oil, NGLs and natural gas and higher oil and natural gas production volumes during the first nine months of 2013. These positive factors were partially offset by increased lease operating expenses, production taxes, exploration costs, general and administrative and cash interest expense in the first nine months of 2013 as compared to the same period in

2012. Refer to "Results of Operations" for more information on the impact of prices and volumes on revenues and for more information on increases and decreases in certain expenses during the first nine months of 2013. Cash flows from operating activities plus $2,304.0 million of proceeds from the issuance of our Senior Notes and $819.6 million of proceeds from the sale of properties were used to finance $1,670.0 million of drilling and development expenditures, $1,200.0 million of net repayments under our credit agreement, $438.3 million of cash acquisition capital expenditures, $42.5 million in investing derivative purchases (net of cash receipts for settlements) and $29.5 million of debt issuance costs. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region during the first nine months of 2013 (in thousands):

Table of Contents

	Drilling and Development Expenditures(1)	Undeveloped Leasehold Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 1,428,386	$ 79,280	$ 37,692	$ 1,545,358	80 %
Permian Basin	210,566	6,089	28,520	245,175	13 %
Mid-Continent	43,343	10,010	1,040	54,393	3 %
Gulf Coast	11,745	32,001	4,305	48,051	2 %
Michigan	2,939	33,025	78	36,042	2 %
Total incurred	1,696,979	160,405	71,635	1,929,019	100 %
Increase in accrued capital expenditures	(48,150)	-	-	(48,150)	
Total paid	$ 1,648,829	$ 160,405	$ 71,635	$ 1,880,869	

(1) For purposes of this schedule, exploratory dry hole costs of $21.2 million are excluded from drilling and development expenditures as reported on the statement of cash flows and instead have been included in exploration expenditures above.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2013 exploration and development budget is $2,500.0 million, of which $571.0 million remains to be spent in 2013. We expect to fund our remaining 2013 capital budget with net cash provided by our operating activities and with cash on hand from our recent senior note offerings. This represents an 18% increase from the $2,111.5 million incurred on exploration, development and acreage expenditures during 2012, and based on this level of capital spending, we are forecasting production growth in 2013 over our 2012 production level of 30.2 MMBOE. We expect to allocate $2,184.9 million of our 2013 budget to exploration and development activity, $170.0 million to undeveloped acreage and $145.1 million to facilities. Although we have only budgeted $170.0 million for undeveloped leasehold expenditures in 2013, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should additional attractive acquisition opportunities arise or exploration and development expenditures exceed $2,500.0 million, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, agreements with industry partners or divestitures of certain oil and gas property interests. Our level of exploration, development and acreage expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, 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 Corporation (“Whiting Oil and Gas”), our wholly-owned subsidiary, has a credit agreement with a syndicate of banks that, as of September 30, 2013, had a borrowing base of $2.15 billion, of which $1.2 billion has been committed by lenders and is available for borrowing. We may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.15 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of September 30, 2013, we had $1,197.0 million of available borrowing capacity, which was net of $3.0 million in letters of credit with no borrowings outstanding.

Table of Contents

In July 2013, upon closing of sale of the Postle Properties discussed under "Acquisition and Divestiture Highlights" above, the credit agreement borrowing base and aggregate commitments decreased from $2.5 billion to $2.15 billion. In September 2013, Whiting Oil and Gas entered into an amendment to its existing credit agreement to permit the issuance of up to $2.3 billion of senior notes without a reduction in the borrowing base, and upon completion of the first Senior Notes offering discussed under "Financing Highlights" above, we voluntarily reduced the aggregate commitments under the credit agreement from $2.15 billion to $1.2 billion.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to the 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. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 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, 2013, $47.0 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until April 2016, when the entire amount borrowed is due. Interest 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 0.50% or an adjusted LIBOR rate plus 1.00%, 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 lesser of the aggregate commitments of the lenders or the borrowing base.

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	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	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. 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 the net assets of Whiting Oil and Gas. The credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. We were in compliance with our covenants under the credit agreement as of September 30, 2013.

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

Senior Notes and Senior Subordinated Notes. In September 2013, we issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021, and also in September 2013, we issued at 101% of par an additional $400.0 million of 5.75% Senior Notes due March 2021. In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. In October 2005, we issued at par $250.0 million of 7% Senior Subordinated Notes due February 2014 (“2014 Notes”). On October 1, 2013, the trustee under the indenture governing our 2014 Notes provided notice to the holders of such notes that we elected to redeem all of the outstanding 2014 Notes on October 31, 2013.

Table of Contents

The indentures governing the 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 Corporation's credit agreement. Additionally, the indentures governing the notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, 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, 2013. 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 table below does not include our Production Participation Plan liability of $156.8 million (which amount comprises both the long and short-term portions of this obligation) as of September 30, 2013, since we cannot determine with accuracy the timing or amounts of future payments other than the short-term portion. The following table summarizes our obligations and commitments as of September 30, 2013 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

		Payments due by period			
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$2,900,000	$250,000	$-	$-	$2,650,000
Cash interest expense on debt (2)	934,417	152,583	293,500	293,500	194,834
Derivative contract liability fair value (3)	20,663	20,164	499	-	-
Asset retirement obligations (4)	110,789	11,730	12,529	12,708	73,822
Tax sharing liability (5)	23,876	1,452	22,424	-	-
Purchase obligations (6)	655,736	77,424	223,114	130,286	224,912
Drilling rig contracts (7)	119,289	80,479	38,810	-	-
Operating leases (8)	30,278	6,199	11,529	10,545	2,005
Total	$4,795,048	$600,031	$602,405	$447,039	$3,145,573

(1) Long-term debt consists of the principal amounts of the 7% Senior Subordinated Notes due 2014, the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019 and the 5.75% Senior Notes due 2021.

(2) Cash interest expense on the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019 and the 5.75% Senior Notes due 2021 is estimated assuming no principal repayment until the due dates of the instruments, and cash interest expense on the 7% Senior Subordinated Notes due 2014 is estimated assuming principal repayment upon redemption on October 31, 2013. No cash interest expense is assumed on the credit facility as there were no borrowings outstanding at September 30, 2013.

(3) The above derivative obligation at September 30, 2013 primarily consists of (i) a $19.8 million fair value liability for derivative contracts we have entered into on our own behalf, primarily in the form of costless collars, to hedge our exposure to crude oil price fluctuations and (ii) a $0.7 million payable to Trust II for derivative contracts that we have entered into but have in turn conveyed to Trust II (although these derivatives are in a fair value asset position at quarter end, 90% of such derivative assets are due to Trust II under the terms of the conveyance). With respect to only a portion of our open derivative contracts at September 30, 2013 with certain counterparties, the

forward price curve for crude oil generally exceeded the price curve that was in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market risk and commodity price volatility.

(4) 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 facilities.

Table of Contents

(5) Amounts shown represent the present value of estimated payments due to Alliant Energy based on projected future income tax benefits attributable to an increase in our tax bases. As a result of the Tax Separation and Indemnification Agreement signed with Alliant Energy, the increased tax bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay Alliant Energy 90% of the tax benefits we realize annually as a result of this step up in tax basis for the years ending on or prior to December 31, 2013. In November 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years.

(6) We have three take-or-pay purchase agreements, one agreement expiring in December 2014, one agreement expiring in December 2017 and one agreement expiring in December 2029, whereby we have committed to buy certain volumes of CO2 for use in the enhanced oil recovery ("EOR") project in our North Ward Estes field in Texas. The purchase agreements are with two different suppliers. Under the terms of the agreements, we are obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. In addition, we have one ship-or-pay agreement expiring in December 2017, whereby we have committed to transport a minimum daily volume of CO2 via a certain pipeline or else pay for any deficiencies at a price stipulated in the contract. The CO2 volumes planned for use in the EOR project in the North Ward Estes field currently exceed the minimum daily volumes specified in all of these agreements. Therefore, we expect to avoid any payments for deficiencies. The purchasing obligations reported above represent our minimum financial commitment pursuant to the terms of these contracts. However, our actual expenditures under these contracts are expected to exceed the minimum commitments presented above.

(7) We currently have ten drilling rigs under long-term contract, of which one drilling rig expires in 2013, six in 2014, one in 2015 and two in 2016. All of these rigs are operating in the Rocky Mountains region. As of September 30, 2013, early termination of the remaining contracts would require termination penalties of $92.5 million, which would be in lieu of paying the remaining drilling commitments of $119.3 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(8) We lease 172,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2018, 47,900 square feet of office space in Midland, Texas expiring in 2020 and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016. In addition, we entered into a lease for several residential apartments in Watford City and Dickinson, North Dakota under an operating lease agreement expiring in 2015.

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 as well as sales proceeds from certain oil and gas property divestitures, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development 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 the Adopted and Recently Issued Accounting Pronouncements footnote in the notes to 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, 2012.

Table of Contents

Effects of Inflation and Pricing

We experienced increased costs during 2012 and the first nine months of 2013 due to increased 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 put 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 the 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, higher prices for oil and natural gas 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 oil, NGL or natural gas prices; our level of success in exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; our ability to obtain sufficient quantities of CO_2 necessary to carry out our EOR projects; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; risks related to our level of indebtedness and periodic redeterminations of the borrowing base under our credit agreement; 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 and acquisitions; federal and state initiatives relating to the regulation of hydraulic fracturing; the potential impact of federal debt reduction initiatives and tax reform legislation being considered by the U.S. Federal government that could have a negative effect on the oil and gas industry; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete potential asset dispositions and the risks related thereto; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; 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 in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption “Risk Factors” in this Quarterly Report on Form 10-Q. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2012 and have not materially changed since that report was filed.

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. The prices we receive for our production depend on numerous factors beyond our control. Based on production for the first nine months of 2013, our income before income taxes for 2013 would have moved up or down $180.6 million for each 10% change in oil prices per Bbl, $8.0 million for each 10% change in NGL prices per Bbl and $7.7 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, although we evaluate 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. For derivative instruments that were previously designated as cash flow hedges in periods prior to April 1, 2009, the effective portion of derivative gains and losses is reclassified from accumulated other comprehensive income into earnings in the same period that the forecasted transactions effect income.

Commodity Derivative Contracts—Our outstanding hedges as of October 1, 2013 are summarized below:

Whiting Petroleum Corporation

Derivative Instrument	Commodity	Period	Average Monthly Volume (Bbl)	Weighted Average NYMEX Price
Collars	Crude Oil	10/2013	290,000	$47.67/$90.21
	Crude Oil	11/2013	190,000	$47.22/$85.06
Three-way collars(1)	Crude Oil	10/2013 to 12/2013	1,040,000	$71.25/$85.63/$113.95
	Crude Oil	01/2014 to 03/2014	1,200,000	$71.00/$85.00/$103.56
	Crude Oil	04/2014 to 06/2014	1,200,000	$71.00/$85.00/$103.56
	Crude Oil	07/2014 to 09/2014	1,200,000	$71.00/$85.00/$103.56
	Crude Oil	10/2014 to 12/2014	1,200,000	$71.00/$85.00/$103.56

(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.

Fixed-price Natural Gas Contracts. We have various fixed-price gas sales contracts with end users for a portion of the natural gas we produce in Colorado and Utah. Our future production volumes projected to be sold under these fixed-price contracts as of October 1, 2013 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	10/2013 to 12/2013	368,000	$5.47
Natural Gas	01/2014 to 03/2014	330,000	$5.49
Natural Gas	04/2014 to 06/2014	333,667	$5.49
Natural Gas	07/2014 to 09/2014	337,333	$5.49
Natural Gas	10/2014 to 12/2014	337,333	$5.49

Commodity Derivatives Conveyed to Whiting USA Trust II. In connection with our conveyance on March 28, 2012 of a term net profits interest to Whiting USA Trust II ("Trust II"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 623 MBbl of crude oil from 2013 through 2014, have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. This results in third-party public holders of Trust II units receiving 90%, while we retain 10%, of the future economic results of such hedges. No additional hedges are allowed to be placed on Trust II assets.

The table below summarizes all of the outstanding costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Trust II (of which we retain 10% of the future economic results and third-party public holders of Trust II units receive 90% of the future economic results):

Conveyed to Whiting USA Trust II

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	NYMEX Floor/Ceiling
Collars	Crude Oil	10/2013 to 12/2013	43,400	$80.00/$122.50
	Crude Oil	01/2014 to 03/2014	42,500	$80.00/$122.50
	Crude Oil	04/2014 to 06/2014	41,500	$80.00/$122.50
	Crude Oil	07/2014 to 09/2014	40,600	$80.00/$122.50
	Crude Oil	10/2014 to 12/2014	39,700	$80.00/$122.50

The collared hedges shown in the tables above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil collars outstanding as of September 30, 2013, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of September 30, 2013 would cause a decrease or increase, respectively, of $93.0 million in our commodity derivative (gain) loss.

Embedded Commodity Derivative Contract—The price we pay for oil field products and services significantly impacts our profitability, reserve estimates, access to capital and future growth rate. Typically, as prices for oil and natural gas increase, so do all associated costs. In May 2011, we entered into a long-term contract to purchase CO_2 from 2015 through 2029 for use in our EOR project at our North Ward Estes field in Texas. This contract contains a price adjustment clause that is linked to changes in NYMEX crude oil prices, in order to reduce our exposure to paying higher than the market rates for CO_2 in a climate of declining oil prices. We have determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to the host contract, and we have therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. This embedded commodity derivative contract has not been designated as a hedge, and therefore all changes in fair value since inception have been recorded immediately to earnings. The price per Mcf of CO_2 purchased under this agreement increases or decreases as the average price of NYMEX crude oil likewise increases or decreases. For this embedded commodity derivative contract, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of September 30, 2013 would cause a decrease or increase, respectively, of $13.3 million in our commodity derivative (gain) loss.

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 and Chief Executive Officer and our 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, 2013. Based upon their evaluation of these disclosures controls and procedures, the Chairman and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of September 30, 2013 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.

Table of Contents

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, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

Whiting is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management's opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2012, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

Oil and natural gas prices are very volatile. An extended period of low oil and natural gas prices may adversely affect our business, financial condition, results of operations or cash flows.

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil, NGL and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in regional, domestic and global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity, such as recent conflicts in the Middle East;
- the level of global oil and natural gas exploration and production activity;
- the effects of global credit, financial and economic issues;
- the level of global oil and natural gas inventories;
- developments of United States energy infrastructure, such as the approval to proceed with the Keystone XL pipeline from Hardesty, Alberta to Cushing, Oklahoma and the development of liquefied natural gas exporting facilities and the perceived timing thereof;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas;
- the price and availability of alternative fuels; and
- acts of force majeure.

Moreover, government regulations, such as regulation of oil and natural gas gathering and transportation, can adversely affect commodity prices in the long term.

Table of Contents

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis but also may ultimately reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve quantities. A substantial or extended decline in oil, NGL or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending or borrow any such shortfall. Lower oil, NGL and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the 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.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our development, exploitation, production and exploration activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "— Reserve estimates depend on many assumptions that may turn out to be inaccurate..." later in these Risk Factors for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- delays or limits on the issuance of drilling permits on our federal leases, including as a result of government shutdowns;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs, completion services and CO2;
- equipment failures or accidents;
- adverse weather conditions, such as freezing temperatures, hurricanes and storms;
- reductions in oil, NGL and natural gas prices;
- pipeline takeaway and refining and processing capacity; and
- title problems.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing has been utilized to complete wells in our most active areas located in the states of Colorado, Michigan, Montana, North Dakota and Texas, and we expect it will also be used in the future. Should our exploration and production activities expand to other states, it is likely that we will utilize hydraulic fracturing to complete or recomplete wells in those areas. The process is typically regulated by state oil and gas commissions. However, the U.S. Environmental Protection Agency (the "EPA") has asserted federal regulatory authority over hydraulic fracturing involving diesel under the Safe Drinking Water Act's Underground Injection Control Program and published draft permitting guidance in May 2012 regarding the process for obtaining a permit for hydraulic fracturing involving diesel.

At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities on drinking water resources. The EPA published a progress report of the study in December 2012 and expects to release a draft final report for public comment and peer review by 2014. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office and the White House Council for Environmental Quality. The U.S. Department of the Interior released a draft proposed rule in May 2012 governing hydraulic fracturing in federal and Indian oil and natural gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing, and monitoring of well-stimulation operations, but on January 18, 2013 the agency announced that the Federal Bureau of Land Management will issue a revised draft of the proposed rule in 2013. In addition, legislation has been introduced in Congress from time to time to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances. For example, on June 17, 2011, Texas enacted a law that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production) and the public. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment including groundwater. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays, litigation risk and potential increases in costs. Further, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling or hydraulic fracturing. No assurance can be given as to whether or not similar measures might be considered or implemented in the jurisdictions in which our properties are located. If new laws, regulations or ordinances that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states or local municipalities where our properties are located, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercially paying quantities.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO_2 into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO_2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO_2. Under our CO_2 contracts, if the supplier suffers an inability to deliver its contractually required quantities of CO_2 to us and other parties with whom it has CO_2 contracts, then the supplier may reduce the amount of CO_2 on a pro rata basis it provides to us and such other parties. If this occurs or if we are otherwise limited in the quantities of CO_2 available to us, we may not have sufficient CO_2 to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes could be negatively impacted. These contracts are also structured as “take-or-pay” arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO_2 as part of our enhanced recovery techniques.

The development of the proved undeveloped reserves in the North Ward Estes field may take longer and may require higher levels of capital expenditures than we currently anticipate.

As of December 31, 2012, proved undeveloped reserves comprised 43% of the North Ward Estes field's total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $750.0 million at the North Ward Estes field as of December 31, 2012. This field encompasses 28% of our total estimated future development costs related to proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO_2 injection installations, the success of which is less predictable than traditional development techniques.

Table of Contents

Prospects that we decide to drill may not yield oil or gas in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2012. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flow rates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, from more fully explored prospects, or from producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

If oil, NGL and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties.

Accounting rules require that we periodically review the carrying value of our producing oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, which may include depressed oil, NGL and natural gas prices, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and gas properties. For example, we recorded a $3.2 million impairment write-down during 2011 for the partial impairment of producing properties, primarily natural gas, in California and Michigan. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period recognized.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in our Annual Report on Form 10-K for the year ended December 31, 2012.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as the following:

- historical production from the area compared with production rates from other producing areas;
- the assumed effect of governmental regulation; and
- assumptions about future prices of oil, NGLs and natural gas including differentials, production and development costs, gathering and transportation costs, severance and excise taxes, capital expenditures and availability of funds.

Table of Contents

Therefore, estimates of oil and natural gas reserves are inherently imprecise. Actual future production; oil, NGL and natural gas prices; revenues; taxes; exploration and development expenditures; operating expenses; and quantities of recoverable oil and natural gas reserves, most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in our Annual Report on Form 10-K for the year ended December 31, 2012. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in our Annual Report on Form 10-K for the year ended December 31, 2012, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and current costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the estimate. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2012 would have decreased from $5,407.0 million to $5,398.9 million. If oil prices decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2012 would have decreased from $5,407.0 million to $5,312.0 million.

Risks associated with the production, gathering, transportation and sale of oil, NGLs and natural gas could adversely affect net income and cash flows.

Our net income and cash flows will depend upon, among other things, oil, NGL and natural gas production and the prices and costs incurred to exploit oil and natural gas reserves. Drilling, production or transportation accidents that temporarily or permanently halt the production and sale of oil, NGLs and natural gas will decrease revenues and increase expenditures. For example, accidents may occur that result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any costs incurred in connection with any such accidents that are not insured against will have the effect of reducing net income. Also, we do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. Please read "— Federal and state legislative and regulatory initiatives relating to hydraulic fracturing..." above in these Risk Factors for a discussion of the uncertainty involved in the practice of hydraulic fracturing. In addition, curtailments or damage to pipelines used to transport oil, NGLs and natural gas production to markets for sale could decrease revenues or increase transportation expenses. Any such curtailment or damage to the gathering systems could also require finding alternative means to transport the oil, NGLs and natural gas production, which alternative means could result in additional costs that will have the effect of increasing transportation expenses.

Also, drilling, production and transportation of hydrocarbons bear an inherent risk of loss of containment. Potential consequences include loss of reserves, loss of production, loss of economic value associated with the affected wellbore, contamination of soil, ground water, and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of September 30, 2013, we had no borrowings and $3.0 million in letters of credit outstanding under Whiting Oil and Gas Corporation's credit facility with $1,197.0 million of available borrowing capacity, as well as $2,300.0 million of senior notes outstanding and $600.0 million of senior subordinated notes outstanding. However, on October 1, 2013, we called for redemption on October 31, 2013 all $250.0 million aggregate principal amount of our outstanding 7% Senior Subordinated Notes due 2014.

Table of Contents

We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior notes and our senior subordinated notes and Whiting Oil and Gas Corporation’s credit agreement.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas Corporation’s credit agreement is subject to certain rate variability.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. In addition, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas Corporation’s credit agreement is periodically redetermined based on an evaluation of our oil and gas reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt under the credit agreement.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We may not be able to generate sufficient cash flow to pay the interest on our debt or future borrowings, and equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including Whiting Oil and Gas Corporation’s credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indentures governing our senior notes and our senior subordinated notes and Whiting Oil and Gas Corporation’s credit agreement contain various restrictive covenants that may limit our management’s discretion in certain respects. In particular, these agreements will limit our and our subsidiaries’ ability to, among other things:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our senior or subordinated debt;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets and those of our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, Whiting Oil and Gas Corporation's credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. Also, the indentures under which we issued our senior notes and our senior subordinated 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 these covenants, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. A substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants.

If we fail to comply with the restrictions in the indentures governing our senior notes and our senior subordinated notes or Whiting Oil and Gas Corporation's credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make further funds available to us. Furthermore, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock.

Our exploration and development operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures through a combination of equity and debt issuances, bank borrowings and internally generated cash flows. We intend to finance future capital expenditures with cash flow from operations, existing financing arrangements and certain oil and gas divestitures. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold;
- the costs of producing oil and natural gas; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves, or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels.

Table of Contents

We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities related to future acquisitions.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for additional future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis or within our budget.

The demand for qualified and experienced field personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Additionally, our operations in some instances require supply materials such as CO_2 for production which could become subject to shortage and increasing costs. Shortages of field personnel, drilling rigs, equipment, supplies or personnel or price increases could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition, results of operations or cash flows, or restrict operations.

Table of Contents

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2012, we had identified a drilling inventory of over 2,400 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, ability to extend drilling acreage leases beyond expiration, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage may decline, and we may incur impairment charges if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For example, during the fourth quarter of 2010, we recorded a $5.8 million non-cash charge for the impairment of unproved properties in the central Utah Hingeline play. We may also incur such impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. Additionally, our rights to develop a portion of our undeveloped acreage may expire if not successfully developed or renewed. See “Acreage” in Item 2 of our Annual Report on Form 10-K for the year ended December 31, 2012, for more information relating to the expiration of our rights to develop undeveloped acreage.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain indemnities from sellers for liabilities they may have created.

Our business strategy includes a continuing acquisition program. From 2004 through September 30, 2013, we completed 17 separate significant acquisitions of producing properties with a combined purchase price of $2,160.3 million for estimated proved reserves as of the effective dates of the acquisitions of 248.0 MMBOE. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- the assumption of unknown potential environmental and other liabilities, losses or costs, including for example, historical spills or releases for which we are not indemnified or for which our indemnity is inadequate.

53

Table of Contents

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, facility or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit higher revenues in the future in connection with commodity price increases and may result in significant fluctuations in our net income.

We enter into hedging transactions of our oil and natural gas production revenues to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas forward sales contracts, primarily costless collars, placed with major financial institutions. As of October 1, 2013, we had contracts, which include our 10% share of the Whiting USA Trust II hedges, covering the sale of between 1,044,340 and 1,334,340 barrels of oil per month for the remainder of 2013. All of our oil hedges will expire by December 2014. See "Quantitative and Qualitative Disclosure about Market Risk" in Item 3 of this Quarterly Report on Form 10-Q for pricing and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas, or alternatively, we may decide to unwind or restructure the hedging arrangements we previously entered into. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we may otherwise receive from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions or unwind hedging transactions we previously entered into, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

We recognize all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income. Consequently, we may experience significant net losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

An increase in the differential or decrease in the premium between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount, but sometimes at a premium, to the relevant benchmark prices such as NYMEX. A negative difference between the benchmark price and the price received is called a differential and a positive difference is called a premium. The differential and premium may vary significantly due to market conditions, the quality and location of production and other risk factors. We cannot accurately predict oil and natural gas differentials and premiums. Increases in the differential and decreases in the premium between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

Table of Contents

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues and increase capital expenditures.

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of our properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's decisions with respect to the timing and amount of capital expenditures, the period of time over which the operator seeks to generate a return on capital expenditures, inclusion of other participants in drilling wells, and the use of technology, as well as the operator's expertise and financial resources and the operator's relative interest in the field. Operators may also opt to decrease operational activities following a significant decline in oil or natural gas prices. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance. Accordingly, while we use commercially reasonable efforts to cause the operator to act as a reasonably prudent operator, we are limited in our ability to do so.

Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. Thus, some of our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

Table of Contents

Market conditions or operational impediments may hinder our access to oil and gas markets or delay our production.

In connection with our continued development of oil and gas properties, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in these properties, caused by transportation capacity constraints, curtailment of production or the interruption of transporting oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil, NGL and natural gas production depends on a number of factors, including the demand for and supply of oil, NGLs and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Additionally, entering into arrangements for these services exposes us to the risk that third parties will default on their obligations under such arrangements. Our failure to obtain such services on acceptable terms or the default by a third party on their obligation to provide such services could materially harm our business. We may be required to shut in wells for a lack of a market or because access to gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- unitization and pooling of properties; and
- taxation.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our financial condition and results of operations.

Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations.

Our oil and gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities and concentration of materials that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Private parties, including the surface owners of properties upon which we drill, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may not be able to recover some or any of these costs from insurance. Moreover, federal law and some state laws allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

Table of Contents

Changes in environmental laws and regulations occur frequently and may have a materially adverse impact on our business. For example, in August 2012, the EPA published final rules under the federal Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from certain fractured and refractured gas wells for which well completion operations are conducted and, in particular, requiring some of these wells to use reduced emission completions, also known as “green completions”, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, pneumatic controllers and storage vessels. Any increased governmental regulation or suspension of oil and natural gas exploration or production activities that arises out of these incidents could result in higher operating costs, which could, in turn, adversely affect our operating results. Also, for instance, any changes in laws or regulations that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition as well as those of the oil and gas industry in general.

Climate change legislation or regulations restricting emissions of “greenhouse gasses” could result in increased operating costs and reduced demand for oil and gas that we produce.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (“GHG”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climate changes. Based on these findings, the EPA has begun adopting and implementing regulations that restrict emissions of GHG under existing provisions of the federal Clean Air Act (the “CAA”), including one rule that limits emissions of GHG from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (“PSD”) and Title V permitting programs. This rule “tailors” these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions consistent with guidance for determining “best available control technology” standards for GHG, which guidance was published by the EPA in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA is issuing new regulations that limit emissions of GHG associated with our operations which will require us to incur costs to inventory and reduce emissions of GHG associated with our operations and which could adversely affect demand for the oil, NGLs and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

57

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.

The loss of senior management or technical personnel could adversely affect us.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, Chairman and Chief Executive Officer; James T. Brown, President and Chief Operating Officer; Mark R. Williams, Senior Vice President, Exploration and Development; Steven A. Kranker, Vice President, Reservoir Engineering/Acquisitions; Rick A. Ross, Vice President, Operations; David M. Seery, Vice President, Land; Michael J. Stevens, Vice President and Chief Financial Officer; or Peter W. Hagist, Vice President, Permian Operations, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Competition in the oil and gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated or deferred as a result of future legislation.

In April 2013, President Obama's Administration released its proposed federal budget for fiscal year 2014 that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to:

Table of Contents

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for U.S. oil and gas production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation containing these or similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such changes could negatively affect our financial condition and results of operations.

In connection with the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, new regulations forthcoming in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to manage our risks related to oil and gas commodity price volatility.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission (the "CFTC") and the SEC for transactions by non-financial institutions to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and to otherwise manage our financial risks related to volatility in oil and gas commodity prices.

Item 6. Exhibits

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

Table of Contents

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 25th day of October, 2013.

WHITING PETROLEUM CORPORATION

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

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

By /s/ Brent P. Jensen
Brent P. Jensen
Controller and Treasurer

Table of Contents

EXHIBIT INDEX

Exhibit Number	Exhibit Description
(4.1)	Fifth Amendment to Fifth Amended and Restated Credit Agreement, dated as of September 6, 2013, among Whiting Petroleum Corporation, its subsidiary Whiting Oil and Gas Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other agents and lenders party thereto [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 6, 2013 (File No. 001-31899)].
(4.2)	Notice to JPMorgan Chase Bank, N.A., as Administrative Agent, dated September 9, 2013, to reduce the aggregate commitments under the Fifth Amended and Restated Credit Agreement, as amended. [Incorporated by reference to Exhibit 4.4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 9, 2013 (File No. 001-31899)].
(4.3)	Indenture, dated September 12, 2013, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 9, 2013 (File No. 001-31899)].
(4.4)	First Supplemental Indenture, dated September 12, 2013, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating the 5.000% Senior Notes due 2019 [Incorporated by reference to Exhibit 4.2 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 9, 2013 (File No. 001-31899)].
(4.5)	Second Supplemental Indenture, dated September 12, 2013, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating the 5.750% Senior Notes due 2021 [Incorporated by reference to Exhibit 4.3 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 9, 2013 (File No. 001-31899)].
(4.6)	Third Supplemental Indenture, dated September 26, 2013, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating the 5.750% Senior Notes due 2021 issued on September 26, 2013 [Incorporated by reference to Exhibit 4.3 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 23, 2013 (File No. 001-31899)].
(4.7)	Registration Rights Agreement, dated September 26, 2013, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and the initial purchasers named therein, relating to the $400.0 million aggregate principal amount of 5.750% Senior Notes due 2021 [Incorporated by reference to Exhibit 4.4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 23, 2013 (File No. 001-31899)].
(31.1)	Certification by the Chairman and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	

	Written Statement of the Chairman and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the 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, 2013 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of September 30, 2013 and December 31, 2012, (ii) the Consolidated Statements of Income for the Three and Nine Months Ended September 30, 2013 and 2012, (iii) the Consolidated Statements of Comprehensive Income for the Three and Nine Months Ended September 30, 2013 and 2012, (iv) the Consolidated Statements of Cash Flows for the Nine Months Ended September 30, 2013 and 2012, (v) the Consolidated Statements of Equity for the Nine Months Ended September 30, 2013 and 2012 and (vi) Notes to Consolidated Financial Statements.