WHITING PETROLEUM CORP
Form 10-Q
July 26, 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 June 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 July 15, 2013: 118,654,184 shares.

TABLE OF CONTENTS

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.

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)

	June 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23,312	$ 44,800
Accounts receivable trade, net	345,792	318,265
Prepaid expenses and other	26,011	21,347
Assets held for sale	701,701	-
Total current assets	1,096,816	384,412
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	9,021,657	8,849,515
Unproved properties	381,653	362,483
Other property and equipment	169,549	141,738
Total property and equipment	9,572,859	9,353,736
Less accumulated depreciation, depletion and amortization	(2,691,827)	(2,590,203)
Total property and equipment, net	6,881,032	6,763,533
Debt issuance costs	27,276	28,748
Other long-term assets	112,586	95,726
TOTAL ASSETS	$ 8,117,710	$ 7,272,419
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 250,000	$ -
Accounts payable trade	105,899	131,370
Accrued capital expenditures	104,803	110,663
Accrued liabilities and other	149,064	180,622
Revenues and royalties payable	160,653	149,692
Deposit received on properties held for sale	85,980	-
Taxes payable	44,777	33,283
Derivative liabilities	9,262	21,955
Deferred income taxes	9,803	9,394
Liabilities related to assets held for sale	8,616	-
Total current liabilities	928,857	636,979
Long-term debt	2,000,000	1,800,000
Deferred income taxes	1,190,146	1,063,681
Derivative liabilities	857	1,678
Production Participation Plan liability	106,613	94,483
Asset retirement obligations	89,675	86,179
Deferred gain on sale	95,139	110,395

Other long-term liabilities		26,072		25,852
Total liabilities		4,437,359		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 June 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; 120,134,157 issued and 118,654,184 outstanding as of June 30, 2013, 118,582,477 issued and 117,631,451 outstanding as of December 31, 2012		120		119
Additional paid-in capital		1,572,835		1,566,717
Accumulated other comprehensive loss		(826)		(1,236)
Retained earnings		2,100,069		1,879,388
Total Whiting shareholders’ equity		3,672,198		3,444,988
Noncontrolling interest		8,153		8,184
Total equity		3,680,351		3,453,172
TOTAL LIABILITIES AND EQUITY	$	8,117,710	$	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 June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
REVENUES AND OTHER INCOME:				
Oil, NGL and natural gas sales	$ 651,868	$ 492,756	$ 1,256,982	$ 1,051,453
Gain (loss) on hedging activities	(437)	759	(648)	1,886
Amortization of deferred gain on sale	7,954	8,892	15,930	12,645
Gain (loss) on sale of properties	3,387	(362)	3,432	(362)
Interest income and other	797	129	1,244	258
Total revenues and other income	663,569	502,174	1,276,940	1,065,880
COSTS AND EXPENSES:				
Lease operating	105,080	89,504	204,958	184,294
Production taxes	53,814	40,763	105,085	85,374
Depreciation, depletion and amortization	223,446	160,589	424,605	316,709
Exploration and impairment	43,393	27,902	80,673	55,480
General and administrative	29,213	25,209	58,098	59,577
Interest expense	23,121	17,905	44,591	36,361
Change in Production Participation Plan liability	7,723	(953)	12,130	(18)
Commodity derivative (gain) loss, net	(30,192)	(100,025)	1,065	(70,622)
Total costs and expenses	455,598	260,894	931,205	667,155
INCOME BEFORE INCOME TAXES	207,971	241,280	345,735	398,725
INCOME TAX EXPENSE (BENEFIT):				
Current	(2,511)	1,109	(2,089)	2,535
Deferred	75,538	89,320	126,636	146,893
Total income tax expense	73,027	90,429	124,547	149,428
NET INCOME	134,944	150,851	221,188	249,297
Net loss attributable to noncontrolling interest	12	31	31	55
	134,956	150,882	221,219	249,352

NET INCOME AVAILABLE TO SHAREHOLDERS								
Preferred stock dividends		(269)		(270)		(538)		(539)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$	134,687	$	150,612	$	220,681	$	248,813
EARNINGS PER COMMON SHARE:								
Basic	$	1.14	$	1.28	$	1.87	$	2.12
Diluted	$	1.14	$	1.27	$	1.86	$	2.10
WEIGHTED AVERAGE SHARES OUTSTANDING:								
Basic		117,930		117,622		117,859		117,569
Diluted		118,901		118,853		118,929		118,889

See notes to consolidated financial statements.

Table of Contents

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
NET INCOME	$ 134,944	$ 150,851	$ 221,188	$ 249,297
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:				
OCI amortization on de-designated hedges(1)(2)	277	(479)	410	(1,191)
Total other comprehensive income (loss), net of tax	277	(479)	410	(1,191)
COMPREHENSIVE INCOME	135,221	150,372	221,598	248,106
Comprehensive loss attributable to noncontrolling interest	12	31	31	55
COMPREHENSIVE INCOME ATTRIBUTABLE TO WHITING	$ 135,233	$ 150,403	$ 221,629	$ 248,161

(1) Presented net of income tax expense of $160 and income tax benefit of $280 for the three months ended June 30, 2013 and 2012, respectively, and income tax expense of $238 and income tax benefit of $695 for the six months ended June 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)

	Six Months Ended June 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 221,188	$ 249,297
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	424,605	316,709
Deferred income tax expense	126,636	146,893
Amortization of debt issuance costs and debt discount	4,950	4,691
Stock-based compensation	11,632	8,818
Amortization of deferred gain on sale	(15,930)	(12,645)
(Gain) loss on sale of properties	(3,432)	362
Undeveloped leasehold and oil and gas property impairments	37,464	32,226
Exploratory dry hole costs	11,628	255
Change in Production Participation Plan liability	12,130	(18)
Unrealized gain on derivative contracts	(10,614)	(93,370)
Other, net	(9,359)	(13,248)
Changes in current assets and liabilities:		
Accounts receivable trade	(27,527)	(31,157)
Prepaid expenses and other	(10,738)	(1,624)
Accounts payable trade and accrued liabilities	(54,980)	11,576
Revenues and royalties payable	11,084	12,516
Taxes payable	11,494	3,904
Net cash provided by operating activities	740,231	635,185
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(129,803)	(89,858)
Drilling and development capital expenditures	(1,109,852)	(979,522)
Proceeds from sale of oil and gas properties	3,127	68,423
Deposit received on properties held for sale	85,980	-
Net proceeds from sale of 18,400,000 units in Whiting USA Trust II	-	323,022
Issuance of note receivable	(10,004)	-
Cash paid for investing derivatives	(44,900)	-
Cash settlements received on investing derivatives	2,371	-
Net cash used in investing activities	(1,203,081)	(677,935)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Preferred stock dividends paid	(538)	(539)
Long-term borrowings under credit agreement	1,300,000	1,150,000
Repayments of long-term borrowings under credit agreement	(850,000)	(1,110,000)
Debt issuance costs	(2,586)	(20)
Restricted stock used for tax withholdings	(5,514)	(5,695)
Net cash provided by financing activities	441,362	33,746

NET CHANGE IN CASH AND CASH EQUIVALENTS		(21,488	)		(9,004	)
CASH AND CASH EQUIVALENTS:						
Beginning of period		44,800			15,811	
End of period	$	23,312		$	6,807	
NONCASH INVESTING ACTIVITIES:						
Accrued capital expenditures(1)	$	109,744		$	109,635	

(1) 2013 amount includes $4,941 related to accrued capital expenditures for the Postle Properties, which are recorded as assets held for sale as of June 30, 2013 as described in Note 12 to these consolidated financial statements.

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	Retained	Total Whiting Shareholders'	Noncontrolling	Total
	Shares	Amount	Shares	Amount	Capital	(Loss)	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	-	-	-	-	-	-	249,352	249,352	(55)	249,297
Other comprehensive income (loss)	-	-	-	-	-	(1,191)	-	(1,191)	-	(1,191)
Restricted stock issued	-	-	592	1	(1)	-	-	-	-	-
Restricted stock forfeited	-	-	(6)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(106)	-	(5,695)	-	-	(5,695)	-	(5,695)
Stock-based compensation	-	-	-	-	8,818	-	-	8,818	-	8,818
Preferred dividends paid	-	-	-	-	-	-	(539)	(539)	-	(539)
BALANCES-June 30, 2012	172	$-	118,585	$119	$1,557,345	$(951)	$1,715,089	$3,271,602	$8,219	$3,279,821
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	-	-	-	-	-	-	221,219	221,219	(31)	221,188
Other comprehensive income	-	-	-	-	-	410	-	410	-	410
Conversion of preferred stock to common	(172)	-	794	1	-	-	-	1	-	1
Restricted stock issued	-	-	941	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(69)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(114)	-	(5,514)	-	-	(5,514)	-	(5,514)
Stock-based compensation	-	-	-	-	11,632	-	-	11,632	-	11,632
Preferred dividends paid	-	-	-	-	-	-	(538)	(538)	-	(538)
BALANCES-June 30, 2013	-	$-	120,134	$120	$1,572,835	$(826)	$2,100,069	$3,672,198	$8,153	$3,680,351

See notes to consolidated financial statements.

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, Mid-Continent, Michigan and Gulf Coast 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 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 and Divestitures

There were no significant acquisitions or divestitures during the six months ended June 30, 2013.

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.

Table of Contents

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.

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 June 30, 2013 and December 31, 2012 (in thousands):

	June 30, 2013	December 31, 2012
Credit agreement	$ 1,650,000	$ 1,200,000
7% Senior Subordinated Notes due 2014	250,000	250,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
Total debt	$ 2,250,000	$ 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. As of June 30, 2013, this credit facility had a borrowing base of $2.5 billion with $847.6 million of available borrowing capacity, which is net of $1,650.0 million in borrowings and $2.4 million in letters of credit outstanding. During the second quarter of 2013, the lenders under the credit agreement increased their aggregate commitments under the agreement from $2.0 billion to $2.5 billion. Upon closing of the Postle divestiture discussed in the Subsequent Event footnote, the credit agreement borrowing base and aggregate commitments decreased from $2.5 billion to $2.15 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 June 30, 2013, $47.6

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. At June 30, 2013, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.2%. 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 June 30, 2013, total restricted net assets were $3,833.4 million, and the amount of retained earnings free from restrictions was $21.2 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 June 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 Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due February 2014. The estimated fair value of these notes was $255.6 million as of June 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.

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 $372.3 million as of June 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.

Table of Contents

The notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of 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 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 June 30, 2013 and December 31, 2012 were $11.0 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 six months ended June 30, 2013 (in thousands):

Asset retirement obligation at January 1, 2013	$97,818
Additional liability incurred	6,561
Revisions in estimated cash flows	-
Accretion expense	5,619
Obligations on sold properties	(2)
Liabilities settled	(5,748)
Asset retirement obligation at June 30, 2013(1)	$104,248

(1) Includes $3,553 related to asset retirement obligations for the Postle Properties, which are recorded as assets held for sale as of June 30, 2013 as described in the Subsequent Event footnote.

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.

12

Table of Contents

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 July 15, 2013.

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price for Crude Oil (per Bbl)
Collars	Jul – Dec 2013	1,376,370	\$ 48.23 - \$ 90.12
	Jan – Dec 2014	49,290	\$ 80.00 - \$122.50
Three-way collars(1)	Jul – Dec 2013	6,240,000	\$71.25 - \$85.63 - \$113.95
	Jan – Dec 2014	9,600,000	\$71.50 - \$85.00 - \$101.91
	Total	17,265,660	

(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 Postle divestiture discussed in the Subsequent Event 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.

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	Jul – Dec 2013	26,370	\$80.00 - \$122.50

Jan – Dec 2014	49,290	\$80.00 - \$122.50
Total	75,660	

13

Table of Contents

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	Jul – Dec 2013	237,330	$80.00 - $122.50
	Jan – Dec 2014	443,610	$80.00 - $122.50
	Total	680,940	

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 June 30, 2013, the estimated fair value of the embedded derivative in this CO2 purchase contract was an asset of $33.0 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.

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 six months ended June 30, 2013 and 2012 (in thousands):

ASC 815 Cash Flow		Gain (Loss) Reclassified from AOCI into Income (Effective Portion) (1) Six Months Ended June 30,	
Hedging Relationships	Income Statement Classification	2013	2012
Commodity contracts	Gain (loss) on hedging activities	$ (648)	$ 1,886

ASC 815 Cash Flow		Gain (Loss) Reclassified from AOCI into Income (Effective Portion) (1) Three Months Ended June 30,	
Hedging Relationships	Income Statement Classification	2013	2012
Commodity contracts	Gain (loss) on hedging activities	$ (437)	$ 759

(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.

Table of Contents

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Six Months Ended June 30, 2013	2012
Commodity contracts	Commodity derivative (gain) loss, net	$ 10,406	$ (65,687)
Embedded commodity contracts	Commodity derivative (gain) loss, net	(9,341)	(4,935)
Total		$ 1,065	$ (70,622)

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Three Months Ended March 31, 2013	2012
Commodity contracts	Commodity derivative (gain) loss, net	$ (23,854)	$ (89,524)
Embedded commodity contracts	Commodity derivative (gain) loss, net	(6,338)	(10,501)
Total		$ (30,192)	$ (100,025)

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):

		June 30, 2013(1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 18,628	$ (15,185)	$ 3,443
Commodity contracts	Assets held for sale	33,721	-	33,721
Commodity contracts	Other long-term assets	15,865	(12,559)	3,306
Embedded commodity contracts	Other long-term assets	33,057	-	33,057
Total derivative assets		$ 101,271	$ (27,744)	$ 73,527
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 24,448	$ (15,186)	$ 9,262
Commodity contracts	Non-current derivative liabilities	13,415	(12,558)	857

Total derivative liabilities	$ 37,863	$ (27,744)	$ 10,119

15

Table of Contents

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:

- 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.

Table of Contents

The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of June 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 June 30, 2013
Financial Assets				
Commodity derivatives – current	$ -	$ 37,164	$ -	$ 37,164
Commodity derivatives – non-current	-	3,306	-	3,306
Embedded commodity derivatives – non-current	-	49	33,008	33,057
Total financial assets	$ -	$ 40,519	$ 33,008	$ 73,527
Financial Liabilities				
Commodity derivatives – current	$ -	$ 9,262	$ -	$ 9,262
Commodity derivatives – non-current	-	857	-	857
Total financial liabilities	$ -	$ 10,119	$ -	$ 10,119

	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
Embedded commodity derivatives – non-current	-	-	23,715	23,715
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:

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.

Table of Contents

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 six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Fair value asset, beginning of period	$26,718	$8,866	$23,715	$12,980
Unrealized gains (losses) on embedded commodity derivative contracts included in earnings(1)	6,290	8,812	9,293	4,698
Transfers into (out of) Level 3	-	-	-	-
Fair value asset, end of period	$33,008	$17,678	$33,008	$17,678

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

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 June 30, 2013 (in thousands)	Valuation Technique	Unobservable Input	Range (per Bbl)
Embedded commodity derivative	$ 33,008	Option model	Future prices of NYMEX crude oil after December 31, 2020	$80.67 - $102.74

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 2021 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.

Table of Contents

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 six months ended June 30, 2013 and 2012 amounted to $21.5 million and $27.7 million, respectively, charged to general and administrative expense and $2.2 million and $2.9 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 June 30, 2013, the Company used three-year average historical NYMEX prices of $92.27 for crude oil and $3.64 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 June 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 $149.1 million. This amount includes $8.2 million attributable to proved undeveloped oil and gas properties and $23.7 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.

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	35,803
Accrued compensation expense reflected as a current liability	(23,673)
Long-term Production Participation Plan liability at June 30, 2013	$106,613

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 June 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. Each share of preferred stock had a liquidation preference of $100.00 per share plus accumulated and unpaid dividends and was convertible, at a holder's option, into shares of Whiting's common stock based on a conversion price of $21.70815, subject to adjustment upon the occurrence of certain events. The preferred stock was not redeemable by the Company.

Table of Contents

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 June 30, 2013, 5,347,504 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):

	Six Months Ended June 30,	
	2013	2012
Balance at January 1	$8,184	$8,274
Contributions from noncontrolling interest	-	-
Net income (loss)	(31)	(55)
Balance at June 30	$8,153	$8,219

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 six months ended June 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.

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.

Table of Contents

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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Basic Earnings Per Share				
Numerator:				
Net income available to shareholders	$134,956	$150,882	$221,219	$249,352
Preferred stock dividends(1)	(225)	(270)	(494)	(539)
Net income available to common shareholders, basic	$134,731	$150,612	$220,725	$248,813
Denominator:				
Weighted average shares outstanding, basic	117,930	117,622	117,859	117,569
Diluted Earnings Per Share				
Numerator:				
Net income available to common shareholders, basic	$134,731	$150,612	$220,725	$248,813
Preferred stock dividends	269	270	538	539
Adjusted net income available to common shareholders, diluted	$135,000	$150,882	$221,263	$249,352
Denominator:				
Weighted average shares outstanding, basic	117,930	117,622	117,859	117,569
Restricted stock and stock options	267	437	321	526
Convertible perpetual preferred stock	704	794	749	794
Weighted average shares outstanding, diluted	118,901	118,853	118,929	118,889
Earnings per common share, basic	$1.14	$1.28	$1.87	$2.12
Earnings per common share, diluted	$1.14	$1.27	$1.86	$2.10

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

For the three months ended June 30, 2013, the diluted earnings per share calculation excludes (i) the dilutive effect of 814,932 incremental shares of restricted stock that did not meet its market-based vesting criteria as of June 30, 2013, and (ii) the dilutive effect of 945 common shares for stock options that were out-of-the-money. For the three months ended June 30, 2012, the diluted earnings per share calculation excludes (i) the dilutive effect of 138,148 incremental shares of restricted stock that did not meet its market-based vesting criteria as of June 30, 2012, and (ii) the anti-dilutive effect of 25,984 common shares for stock options that were out-of-the-money.

For the six months ended June 30, 2013, the diluted earnings per share calculation excludes (i) the dilutive effect of 645,017 incremental shares of restricted stock that did not meet its market-based vesting criteria as of June 30, 2013, and (ii) the dilutive effect of 174 common shares for stock options that were out-of-the-money. For the six months ended June 30, 2012, the diluted earnings per share calculation excludes (i) the dilutive effect of 129,203 incremental shares of restricted stock that did not meet its market-based vesting criteria as of June 30, 2012, and (ii) the anti-dilutive effect of 10,542 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, Derivative and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse purchase 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.

Table of Contents

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 August 2012, The SEC issued the Disclosure of Payments by Resource Extraction Issuers: Final Rule. The rule would require resource extraction issuers to include in a separate annual report information relating to any payment made by the issuer, its subsidiaries or an entity under the issuer's control, to a foreign government or the Federal government for the purpose of the commercial development of oil, natural gas or minerals. Issuers would be required to provide information about the type and total amount of such payments made for each project related to the commercial development of oil, natural gas or minerals, and the type and total amount of payments made to each government. However, on July 2, 2013, the United States District Court for the District of Columbia vacated the rule due to deficiencies, and absent an appeal of the court's decision, the rule has been remanded to the SEC for revision based on the court's findings. Issuers will not have to comply with the rule until it is reissued by the SEC.

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 a significant impact on the Company's consolidated financial statements.

Table of Contents

12. SUBSEQUENT EVENT

On July 15, 2013, the Company completed the sale to BreitBurn Operating L.P. of Whiting's 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 facilities, oil delivery pipeline, 60% interest in the 120-mile Transpetco CO2 pipeline, CO2 supply contracts, certain crude oil swap contracts and other related assets and liabilities (collectively the "Postle Properties"), effective April 1, 2013, for a cash purchase price of $836.9 million after selling costs and closing adjustments, which is also subject to post-closing adjustments. The Company used the net proceeds from this transaction to repay a portion of the debt outstanding under its credit agreement. Upon closing, the credit agreement borrowing base was decreased from $2.5 billion to $2.15 billion. The net proceeds from this transaction are expected to generate a gain on sale. 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.

Although the transaction closed on July 15, 2013, under the terms of the agreement, Whiting will continue to operate the Postle Properties until October 31, 2013. Also under the terms of the agreement, Whiting committed to sell 59.8 Bcf of CO2 volumes to the buyer through 2021 at market prices specified in the agreement, which are subject to a $2.00 per Mcf floor price.

Upon closing of the transaction, the following crude oil swaps and any of their realized 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	

The following table shows the components of assets and liabilities classified as held for sale as of June 30, 2013 (in thousands):

	Carrying value as of June 30, 2013
Assets	
Prepaid expenses and other	$7,215
Property and equipment:	
Oil and gas properties, successful efforts method:	
Proved properties	967,899
Other property and equipment	8,491
Accumulated depreciation, depletion and amortization	(317,743)
Total property and equipment, net	658,647
Other long-term assets	35,839
Total assets held for sale	$701,701
Liabilities	

Accrued capital expenditures	$4,941
Revenues and royalties payable	122
Asset retirement obligations	3,553
Total liabilities related to assets held for sale	$8,616

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, Mid-Continent, Michigan and Gulf Coast 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 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.

Table of Contents

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:

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

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 36.3 MBOE/d for the second quarter of 2013, representing a 1% increase from 35.8 MBOE/d in the first quarter of 2013. As of June 30, 2013, we had seven drilling rigs active in the Sanish field. Two of these rigs are drilling multiple wells from the same drilling location or well pad ("pad drilling"), and as a result, we are realizing cost efficiencies with the use of multi-well pads in the drilling and completion of wells. We initiated higher density pilot programs in the Sanish and Parshall fields in the second 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 13.3 MBOE/d in the second quarter of 2013, representing a 3% decrease from 13.8 MBOE/d in the first quarter of 2013. As of June 30, 2013, we had six drilling rigs operating in the Pronghorn prospect, making this our second most active area in the Williston Basin. Four of the rigs working in the Pronghorn prospect 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 these prospects as well. However, the shift to pad drilling in this area in the first half of 2013 has resulted in a backlog of 13 wells that were being completed or awaiting completion as of June 30, 2013.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which has a processing capacity of 30 MMcf/d and which primarily processes production from the Pronghorn area. Currently, there is inlet compression in place to process 24 MMcf/d, and as of June 30, 2013 the plant was processing 14

MMcf/d. In November 2012, we began connecting other operators' wells to the plant. We intend to add inlet compression during 2013 in order to fully utilize the 30 MMcf/d 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 oil transmission system. The use of this terminal will reduce our transportation costs per barrel and increase our returns on the development of this prospect.

Hidden Bench/Tarpon. Our Hidden Bench and Tarpon prospects in McKenzie County, North Dakota target the Bakken and Three Forks formations. In the second quarter of 2013, net production from the Hidden Bench/Tarpon prospects averaged 5.9 MBOE/d, representing a 47% increase from 4.0 MBOE/d in the first quarter of 2013. As of June 30, 2013, we had drilled six productive wells in the Tarpon prospect. 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. We have implemented pad drilling at our Tarpon prospect and plan to drill three wells from each pad.

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 second quarter of 2013, net production from the Missouri Breaks prospect averaged 2.7 MBOE/d, representing a 37% increase from 2.0 MBOE/d in the first quarter of 2013. We implemented a 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 9.3 MBOE/d for the second quarter of 2013, which represents a 9% increase from 8.5 MBOE/d in the first quarter of 2013. As of June 30, 2013, we were injecting approximately 350 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. During 2013, we plan to drill at least three wells in the Big Tex prospect, all of which are expected to be horizontal Upper Wolfcamp wells. In late 2012, we completed a well utilizing a cemented liner and a plug and perf completion technique that is providing encouraging early results. Based on the performance of this well, we plan to implement this completion strategy on the horizontal wells drilled in this prospect during 2013.

Redtail. Our Redtail prospect in the Denver Julesberg Basin in Weld County, Colorado targets the Niobrara formation. Our development plan includes drilling up to eight Niobrara “B” wells per spacing unit and four Niobrara “A” wells per spacing unit. We plan to test tighter spacing in the Niobrara “A” and “B” reservoir system, with the potential to drill up to 16 wells per spacing unit compared to our current 12-well plan. 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 for this purpose. The plant’s planned 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. We have ordered the major equipment necessary to construct this plant, and we anticipate having the plant online in early 2014. As of June 30, 2013, we had one drilling rig operating in this area. We recently added a second drilling rig that is pad capable, and we plan to add a third before the end of 2013. We also implemented a new completion design in this prospect, resulting in strong consistent results.

26

Table of Contents

Divestiture Highlight. On July 15, 2013, we completed the sale to BreitBurn Operating L.P. 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 facilities, oil delivery pipeline, 60% interest in the 120-mile Transpetco CO2 pipeline, CO2 supply contracts, certain crude oil swap contracts and other related assets and liabilities (collectively the "Postle Properties"), effective April 1, 2013, for a cash purchase price of $836.9 million after selling costs and closing adjustments, which is also subject to post-closing adjustments. We used the net proceeds from this transaction to repay a portion of the debt outstanding under our credit agreement. The net proceeds from this transaction are expected to generate a gain on sale. In addition, a one-time charge of $23.9 million under the Production Participation Plan (the "Plan") for the sale of the Postle Properties will be incurred during the third quarter of 2013, with an offsetting benefit of $19.4 million also being realized related to a reduction in the Company's long-term Plan liability. The Postle Properties consist 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.

Although the transaction closed on July 15, 2013, under the terms of the agreement, we will continue to operate the Postle Properties until October 31, 2013. Also under the terms of the agreement, we committed to sell 59.8 Bcf of CO2 volumes to the buyer through 2021 at market prices specified in the agreement, which are subject to a $2.00 per Mcf floor price.

Table of Contents

Results of Operations

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

	Six Months Ended June 30,	
	2013	2012
Net production:		
Oil (MMBbl)	13.0	11.1
NGLs (MMBbl)	1.4	1.4
Natural gas (Bcf)	13.0	13.0
Total production (MMBOE)	16.5	14.7
Net sales (in millions):		
Oil (1)	$1,148.1	$950.9
NGLs	56.5	57.1
Natural gas (1)	52.4	43.5
Total oil, NGL and natural gas sales	$1,257.0	$1,051.5
Average sales prices:		
Oil (per Bbl)	$88.65	$85.21
Effect of oil hedges on average price (per Bbl)	(0.95)	(1.94)
Oil net of hedging (per Bbl)	$87.70	$83.27
Average NYMEX price (per Bbl)	$94.28	$98.23
NGLs (per Bbl)	$40.20	$41.73
Natural gas (per Mcf)	$4.04	$3.35
Effect of natural gas hedges on average price (per Mcf)	-	0.06
Natural gas net of hedging (per Mcf)	$4.04	$3.41
Average NYMEX price (per Mcf)	$3.72	$2.47
Cost and expenses (per BOE):		
Lease operating expenses	$12.41	$12.54
Production taxes	$6.36	$5.81
Depreciation, depletion and amortization expense	$25.70	$21.56
General and administrative expenses	$3.52	$4.06

(1) Before consideration of hedging transactions.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $205.5 million to $1,257.0 million when comparing the first half 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 NGL sales volumes increased 3% between periods, while our natural gas sales volumes remained consistent between periods. The oil volume increase resulted primarily from drilling success at our Lewis & Clark/Pronghorn prospects, Sanish and Parshall fields, Hidden Bench/Tarpon prospects, Missouri Breaks prospect and Denver Julesburg Basin ("DJ Basin") prospect. During the first half of 2013, oil production from our Lewis & Clark/Pronghorn prospects increased 515 MBbl, oil production from our Sanish and Parshall fields increased 470 MBbl, oil production from our Hidden Bench/Tarpon prospects increased 395 MBbl, oil production from our Missouri Breaks prospect increased 385 MBbl, and oil production from our DJ Basin prospect increased 220 MBbl over the same period in 2012. These production increases were partially offset by the Whiting USA Trust II ("Trust II") divestiture, which negatively impacted oil production in the first half of 2013 by 295 MBbl. Our NGLs are generally produced concurrently with our crude oil volumes, resulting in a high correlation between fluctuations in our oil quantities sold and our NGL quantities sold in certain areas. As a result, our NGL sales volume increases generally relate to the same areas as our oil volume increases, such as our Lewis & Clark/Pronghorn prospects and our Hidden Bench/Tarpon prospects. The gas volumes were consistent between periods primarily due to new wells drilled and completed during the past twelve months, offset by normal field production decline. Newly drilled wells caused increases in associated gas production of 810 MMcf at our Sanish and Parshall fields and 570 MMcf at our Lewis & Clark/Pronghorn prospects. These gas volumes added 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 655 MMcf when comparing the first half of 2013 to production during the first half of 2012. In addition, the Trust II divestiture in March 2012 negatively impacted gas production in the first half of 2013 by 545 MMcf.

Table of Contents

Also contributing to the above crude oil and NGL production-related increases in net revenue, were a 4% increase in the average sales price realized for oil and a 21% increase in the average sales price realized for natural gas in the first half of 2013 compared to the first half of 2012. These increases were partially offset by a 4% decrease in the average sales price realized for NGLs.

Gain (Loss) on Hedging Activities. Our gain (loss) on hedging activities changed by $2.5 million in 2013 as compared to the first half of 2012, and it consisted of the following (in thousands):

	Six Months Ended June 30,	
	2013	2012
Gains (losses) reclassified from AOCI on de-designated hedges	$(648)	$1,886

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges, and we elected to discontinue all hedge accounting prospectively. Accordingly, each period we reclassify from accumulated other comprehensive income ("AOCI") into earnings unrealized gains (which were frozen in AOCI on the April 1, 2009 de-designation date) upon the expiration of these de-designated crude oil hedges, and we report such non-cash unrealized gains and losses as gain (loss) on hedging activities.

See Item 3, "Quantitative and Qualitative Disclosures about Market Risk," for a list of our outstanding derivatives as of July 15, 2013.

Lease Operating Expenses. Our lease operating expenses ("LOE") during the first half of 2013 were $205.0 million, a $20.7 million increase over the same period in 2012. Higher LOE in 2013 were primarily related to a $26.0 million increase in the cost of oil field goods and services and gas plant operating expenses, both of which were associated with net wells we added during the last twelve months. This increase was partially offset by a decrease in well workover activity from $46.1 million in the first half of 2012 to $40.8 million in the first half of 2013, primarily due to a lower number of well workovers being conducted at our CO2 project at our Postle field and on certain other fields in western Texas.

Our lease operating expenses on a BOE basis, however, decreased during the first half of 2013. LOE per BOE amounted to $12.41 during the first half of 2013, which was down from $12.54 per BOE during the first half of 2012. This decrease was mainly due to higher overall production volumes between periods and the decline in well workover costs, as discussed above.

Production Taxes. Our production taxes during the first half of 2013 were $105.1 million, a $19.7 million increase over the same period in 2012, which increase was primarily due to higher oil, NGL and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.4% and 8.1% for the first half of 2013 and 2012, respectively. Our production tax rate of 8.4% for the first half 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% tax rate.

Table of Contents

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $107.9 million in 2013 as compared to the first half of 2012. The components of our DD&A expense were as follows (in thousands):

	Six Months Ended June 30,	
	2013	2012
Depletion	$416,903	$311,416
Depreciation	2,083	1,657
Accretion of asset retirement obligations	5,619	3,636
Total	$424,605	$316,709

DD&A increased in in the first half of 2013 primarily due to $105.5 million in higher depletion expense between periods. Of this increase, $59.4 million related to higher depletion rates between periods and $46.1 million related to the increase in our overall production volumes during the first half of 2013. On a BOE basis, our overall DD&A rate of $25.70 for the first half of 2013 was 19% higher than the rate of $21.56 for the same period in 2012 due to $2,150.6 million in drilling and development expenditures during the past twelve months, which were partially offset by reserve additions during this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs increased $25.2 million in the first half of 2013 as compared to the same period in 2012. The components of our exploration and impairment costs were as follows (in thousands):

	Six Months Ended June 30,	
	2013	2012
Exploration	$43,209	$23,254
Impairment	37,464	32,226
Total	$80,673	$55,480

Exploration costs increased $20.0 million during the first half of 2013 as compared to the same period in 2012 primarily due to higher exploratory dry hole costs and an increase in geological and geophysical ("G&G") activity. Exploratory dry hole costs for the first half of 2013 totaled $11.6 million, primarily related to two exploratory dry holes drilled in the Permian Basin and Rocky Mountains regions during the second quarter of 2013. We did not drill any exploratory dry holes during the six months ended June 30, 2012. G&G costs, such as seismic studies, amounted to $17.9 million during the first six months of 2013 as compared to $11.2 million during the first six months of 2012.

Impairment expense in the first half 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 $36.4 million in the first half of 2013 as compared to $26.6 million in the first half of 2012. In addition, acreage costs of $5.6 million were written-off to impairment expense in the first half 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):

	Six Months Ended June 30,	
	2013	2012
General and administrative expenses	$112,501	$102,219
Reimbursements and allocations	(54,403)	(42,642)
General and administrative expense, net	$58,098	$59,577

General and administrative expense before reimbursements and allocations (“G&A”) increased $10.3 million during the first half of 2013 as compared to the same period in 2012 primarily due to $15.4 million of higher employee compensation related to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. The increase in G&A was partially offset by an $6.3 million decrease in accrued Plan distributions between periods. Accrued Plan distributions were higher at June 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.

Table of Contents

The increase in reimbursements and allocations for the first half 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 decreased from 6% in the first half of 2012 to 5% in the first half of 2013.

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Senior Subordinated Notes	$20,125	$20,125
Credit agreement	20,080	12,918
Amortization of debt issue costs and debt discount	4,950	4,692
Other	38	58
Capitalized interest	(602)	(1,432)
Total	$44,591	$36,361

The increase in interest expense of $8.2 million between periods was mainly attributable to a $7.2 million increase in the amount of interest incurred on our credit agreement during the first half of 2013 as compared to the first half of 2012. Our credit agreement interest was higher in 2013 due to a greater amount of borrowings outstanding under this facility. Our weighted average debt outstanding during the first half of 2013 was $2,177.5 million versus $1,491.5 million for the first half of 2012. Our weighted average effective cash interest rate was 3.7% during the first half of 2013 compared to 4.4% during the first half 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, and such cash settlement gains and losses (except for settlements on embedded derivatives) are also recorded immediately to earnings as commodity derivative (gain) loss, net. The components of commodity derivative (gain) loss, net were as follows (in thousands):

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Change in unrealized (gains) losses on derivative contracts	$(11,262)	$(91,484)
Realized cash settlement losses	12,327	20,862
Total	$1,065	$(70,622)

With respect to our open derivative contracts at June 30, 2013, the futures curve of forecasted commodity prices ("forward price curve") for crude oil was generally below the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value asset position at June 30, 2013. However, with respect to our open derivative contracts at June 30, 2012, the forward price curve for crude oil generally exceeded the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value liability position at June 30, 2012. The change in unrealized (gains) losses on derivative contracts in the first half of 2013 resulted in an $11.3 million gain due to the downward shift in the forward price curve for NYMEX crude oil from January 1 to June 30, 2013. The change in unrealized (gains) losses on derivative contracts in the first half of 2012 resulted in a $91.5 million gain due to a more significant downward shift in the same forward price curve from January 1 to June 30, 2012.

Table of Contents

Income Tax Expense. Income tax expense totaled $124.5 million for the first six months of 2013 as compared to $149.4 million of income tax for the first six months of 2012, a decrease of $24.9 million that was mainly related to $53.0 million in lower pre-tax income between periods.

Our effective tax rates for the periods ending June 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 half of 2012 to 36.0% for the first half of 2013. This benefit is attributable to additional state tax deductions associated with depreciation and recent North Dakota corporate tax legislation which created a one-time benefit in the first half of 2013.

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

	Three Months Ended June 30,	
	2013	2012
Net production:		
Oil (MMBbl)	6.7	5.6
NGLs (MMBbl)	0.7	0.7
Natural gas (Bcf)	6.6	6.4
Total production (MMBOE)	8.5	7.3
Net sales (in millions):		
Oil (1)	$597.5	$445.7
NGLs	26.2	26.3
Natural gas (1)	28.2	20.8
Total oil, NGL and natural gas sales	$651.9	$492.8
Average sales prices:		
Oil (per Bbl)	$89.15	$79.92
Effect of oil hedges on average price (per Bbl)	(1.05)	(1.35)
Oil net of hedging (per Bbl)	$88.10	$78.57
Average NYMEX price (per Bbl)	$94.23	$93.51
NGLs (per Bbl)	$37.80	$37.45
Natural gas (per Mcf)	$4.27	$3.25
Effect of natural gas hedges on average price (per Mcf)	-	0.06
Natural gas net of hedging (per Mcf)	$4.27	$3.31
Average NYMEX price (per Mcf)	$4.10	$2.21
Cost and expenses (per BOE):		
Lease operating expenses	$12.37	$12.19
Production taxes	$6.33	$5.55
Depreciation, depletion and amortization expense	$26.29	$21.87
General and administrative expenses	$3.44	$3.43

(1) Before consideration of hedging transactions.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $159.1 million to $651.9 million when comparing the second 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 20%, and our natural gas sales volumes increased 4% 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, Missouri Breaks prospect, Lewis & Clark/Pronghorn prospects, Sanish and Parshall fields and DJ Basin prospect. During the second quarter of 2013, oil production from our Hidden Bench/Tarpon prospects increased 280 MBbl, oil production from our Missouri Breaks prospect increased 215 MBbl, oil production from our Lewis & Clark/Pronghorn prospects increased 215 MBbl, oil production from our Sanish and Parshall fields increased 170 MBbl and oil production from our DJ Basin prospect increased 145 MBbl over the same period in 2012. 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 430 MMcf at our Sanish and Parshall fields, 205 MMcf at our Lewis & Clark/Pronghorn prospects and 185 MMcf at our Hidden Bench/Tarpon prospects. 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 315 MMcf comparing the second quarter of 2013 to second quarter 2012 production.

Table of Contents

Also contributing 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 second quarter of 2013 compared to the second quarter of 2012. Our average price for oil before the effects of hedging increased 12%, our average price for NGLs increased 1% between periods, and our average price for natural gas increased 31% between periods.

Gain (Loss) on Hedging Activities. Our gain (loss) on hedging activities changed by $1.2 million in 2013 as compared to the second quarter of 2012, and it consisted of the following (in thousands):

	Three Months Ended June 30,	
	2013	2012
Gains (losses) reclassified from AOCI on de-designated hedges	$(437)	$759

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges, and we elected to discontinue all hedge accounting prospectively. Accordingly, each period we reclassify from AOCI into earnings unrealized gains (which were frozen in AOCI on the April 1, 2009 de-designation date) upon the expiration of these de-designated crude oil hedges, and we report such non-cash unrealized gains and losses as gain (loss) on hedging activities.

See Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of July 15, 2013.

Lease Operating Expenses. Our LOE during the second quarter of 2013 were $105.1 million, a $15.6 million increase over the same period in 2012. Higher LOE in 2013 were primarily related to a $14.3 million increase in the cost of oil field goods and services and gas plant operating expenses, both of which were associated with net wells we added during the last twelve months, as well as a higher level of workover activity. Workovers increased from $19.8 million in the second quarter of 2012 to $21.1 million in the second quarter of 2013, primarily due to a higher number of well workovers being conducted at our CO2 project at North Ward Estes.

Our lease operating expenses on a BOE basis also increased during the second quarter of 2013. LOE per BOE amounted to $12.37 during the second quarter of 2013, which was up from $12.19 per BOE during the second quarter of 2012. This increase was mainly due to higher costs of oil field goods and services and plant expenses 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 second quarter of 2013 were $53.8 million, a $13.1 million increase over the same period in 2012, which increase was primarily due to higher oil, NGL and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis remained consistent at 8.3% for the second quarter of 2013 and 2012.

Table of Contents

Depreciation, Depletion and Amortization. Our DD&A expense increased $62.9 million in 2013 as compared to the second quarter of 2012. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended June 30,	
	2013	2012
Depletion	$220,081	$157,998
Depreciation	999	863
Accretion of asset retirement obligations	2,366	1,728
Total	$223,446	$160,589

DD&A increased in the second quarter of 2013 primarily due to $62.1 million in higher depletion expense between periods. Of this increase, $32.2 million related to higher depletion rates between periods and $29.9 million related to the increase in our overall production volumes during the second quarter of 2013. On a BOE basis, our overall DD&A rate of $26.29 for the second quarter of 2013 was 20% higher than the rate of $21.87 for the same period in 2012 due to $2,150.6 million in drilling and development expenditures during the past twelve months, which were partially offset by reserve additions during this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs increased $15.5 million in the second 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 June 30,	
	2013	2012
Exploration	$24,343	$13,511
Impairment	19,050	14,391
Total	$43,393	$27,902

Exploration costs increased $10.8 million during the second quarter of 2013 as compared to the same period in 2012 primarily due to higher exploratory dry hole costs. During the second quarter of 2013, we drilled two exploratory dry holes in the Permian Basin and Rocky Mountains regions totaling $11.6 million, while we did not drill any exploratory dry holes in the second quarter of 2012. This increase in dry hole costs was partially offset by a decrease in G&G activity. G&G costs, such as seismic studies, amounted to $5.9 million during the second quarter of 2013 as compared to $8.2 million during the second quarter of 2012.

Impairment expense in the second 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 $18.1 million in the second quarter of 2013 as compared to $13.8 million in the second 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 June 30,	
	2013	2012
	$57,429	$47,910

General and administrative expenses		
Reimbursements and allocations	(28,216)	(22,701)
General and administrative expense, net	$29,213	$25,209

General and administrative expense before reimbursements and allocations increased $9.5 million during the second quarter 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 $6.8 million in the second 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. Accrued distributions under the Plan increased $2.3 million between periods.

Table of Contents

The increase in reimbursements and allocations for the second 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 decreased from 5% in the second quarter of 2012 to 4% in the second quarter of 2013.

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

	Three Months Ended June 30,	
	2013	2012
Senior Subordinated Notes	$10,063	$10,063
Credit agreement	10,808	6,117
Amortization of debt issue costs and debt discount	2,516	2,350
Other	14	45
Capitalized interest	(280)	(670)
Total	$23,121	$17,905

The increase in interest expense of $5.2 million between periods was mainly attributable to a $4.7 million increase in the amount of interest incurred on our credit agreement during the second quarter of 2013 as compared to the second quarter of 2012. Our credit agreement interest was higher in 2013 due to a greater amount of borrowings outstanding under this facility. Our weighted average debt outstanding during the second quarter of 2013 was $2,325.3 million versus $1,438.5 million for the second quarter of 2012. Our weighted average effective cash interest rate was 3.6% during the second quarter of 2013 compared to 4.5% during the second 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, and such cash settlement gains and losses (except for settlements on embedded derivatives) are also recorded immediately to earnings as commodity derivative (gain) loss, net. The components of commodity derivative (gain) loss, net were as follows (in thousands):

	Three Months Ended June 30,	
	2013	2012
Change in unrealized (gains) losses on derivative contracts	$(37,216)	$(107,156)
Realized cash settlement losses	7,024	7,131
Total	$(30,192)	$(100,025)

With respect to our open derivative contracts at June 30, 2013, the forward price curve for crude oil was generally below the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value asset position at the end of the second quarter of 2013. However, with respect to our open derivative contracts at June 30, 2012, the forward price curve for crude oil generally exceeded the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value liability position at the end of the second quarter of 2012. The change in unrealized (gains) losses on derivative contracts in the second quarter of 2013 resulted in a $37.2 million gain due to the downward shift in the forward price curve for NYMEX crude oil from

April 1 to June 30, 2013. The change in unrealized (gains) losses on derivative contracts in the second quarter of 2012 resulted in a $107.2 million gain due to a more significant downward shift in the same forward price curve from April 1 to June 30, 2012.

Income Tax Expense. Income tax expense totaled $73.0 million for the second quarter of 2013 as compared to $90.4 million of income tax for the second quarter of 2012, a decrease of $17.4 million that was mainly related to $33.3 million in lower pre-tax income between periods.

Table of Contents

Our effective tax rates for the periods ending June 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 second quarter of 2012 to 35.1% for the second quarter of 2013. This benefit is attributable to additional state tax deductions associated with depreciation and recent North Dakota corporate tax legislation which created a one-time benefit in the second quarter of 2013.

Liquidity and Capital Resources

Overview. At June 30, 2013, our debt to total capitalization ratio was 38.0%, we had $23.3 million of cash on hand and $3,672.2 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. In the first half of 2013, we generated $740.2 million of cash provided by operating activities, an increase of $105.0 million over the same period in 2012. Cash provided by operating activities increased primarily due to higher realized sales prices for oil and natural gas and higher oil production volumes in the first half of 2013. These positive factors were partially offset by lower realized sales prices for NGLs and increased lease operating expenses, production taxes, exploration costs and cash interest expense in the first half 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 half of 2013. Cash flows from operating activities plus $450.0 million in net borrowings under our credit agreement and an $86.0 million deposit received for the sale of the Postle Properties were used to finance $1,109.9 million of drilling and development expenditures, $129.8 million of cash acquisition capital expenditures and $42.5 million in investing derivative purchases (net of cash receipts for settlements). The following chart details our exploration, development and undeveloped acreage expenditures incurred by region during the first half of 2013 (in thousands):

	Drilling and Development Expenditures(1)	Undeveloped Leasehold Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 901,277	$ 22,337	$ 20,575	$ 944,189	77 %
Permian Basin	144,161	586	18,777	163,524	13 %
Mid-Continent	44,080	8,918	1,291	54,289	4 %
Gulf Coast	6,412	27,955	2,544	36,911	3 %
Michigan	1,375	32,152	22	33,549	3 %
Total incurred	1,097,305	91,948	43,209	1,232,462	100 %
Decrease in accrued capital expenditures	919	-	-	919	
Total paid	$ 1,098,224	$ 91,948	$ 43,209	$ 1,233,381	

(1) For purposes of this schedule, exploratory dry hole costs of $11.6 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, which we expect to fund substantially with net cash provided by our operating activities, borrowings under our credit facility and certain oil and gas property divestitures. 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 $2,217.0 million of our 2013 budget to exploration and development activity, $137.9 million to undeveloped acreage and $145.1 million to facilities. Although we have only budgeted $137.9 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.

Table of Contents

Credit Agreement. Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), our wholly-owned subsidiary, has a credit agreement with a syndicate of banks. As of June 30, 2013, this credit facility had a borrowing base of $2.5 billion with $847.6 million of available borrowing capacity, which was net of $1,650.0 million in borrowings and $2.4 million in letters of credit outstanding. During the second quarter of 2013, the lenders under the credit agreement increased their aggregate commitments under the agreement from $2.0 billion to $2.5 billion. Upon closing of the Postle divestiture discussed above under “2013 Highlights and Future Considerations”, the credit agreement borrowing base and aggregate commitments decreased from $2.5 billion to $2.15 billion. We used the net proceeds from this property sale to repay a portion of the debt outstanding under our credit agreement. Assuming this divestiture transaction had closed on June 30, 2013, net borrowings outstanding under our credit agreement would have been $900.0 million.

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 June 30, 2013, $47.6 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 June 30, 2013.

Table of Contents

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 Subordinated Notes. 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. We plan to repay the 7% Senior Subordinated Notes due in 2014 in their entirety when they mature.

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 June 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 $130.3 million (which amount comprises both the long and short-term portions of this obligation) as of June 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 June 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)	$2,250,000	$250,000	$1,650,000	$-	$350,000
Cash interest expense on debt (2)	230,988	69,258	110,542	45,500	5,688
Derivative contract liability fair value (3)	10,119	9,262	857	-	-
Asset retirement obligations (4)	104,248	11,020	12,522	12,698	68,008
Tax sharing liability (5)	23,418	1,452	21,966	-	-
Purchase obligations (6)	673,384	71,513	214,210	147,366	240,295
Drilling rig contracts (7)	140,702	85,932	54,770	-	-
Operating leases (8)	31,583	5,939	11,748	10,555	3,341
Total	$3,464,442	$504,376	$2,076,615	$216,119	$667,332

(1) Long-term debt consists of the 7% Senior Subordinated Notes due 2014, the 6.5% Senior Subordinated Notes due 2018 and the outstanding borrowings under our credit agreement due in 2016, and assumes no principal repayment until the due date of the instruments.

(2) Cash interest expense on the 7% Senior Subordinated Notes due 2014 and the 6.5% Senior Subordinated Notes due 2018 is estimated assuming no principal repayment until the due dates of the instruments. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the 2016 instrument due date and is estimated at a fixed interest rate of 2.2%.

38

Table of Contents

(3) The above derivative obligation at June 30, 2013 primarily consists of (i) an $8.6 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 $1.5 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 June 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.

(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 four take-or-pay purchase agreements, two agreements 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 enhanced oil recovery ("EOR") projects in our Postle field in Oklahoma and our North Ward Estes field in Texas. The purchase agreements are with three 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 two ship-or-pay agreements with two different parties, one expiring in December 2017 and one expiring in June 2023, whereby we have committed to transport a minimum daily volume of CO2 via certain pipelines or else pay for any deficiencies at a price stipulated in the contract. The CO2 volumes planned for use in the EOR projects in the Postle and North Ward Estes fields 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. The CO2 volumes purchased and delivered under one of the take-or-pay agreements expiring in December 2014 and the ship-or-pay agreement expiring in June 2023 are used at the EOR project in our Postle field, and these contracts were assigned to Breitburn Operating L.P. in association with the divestiture of these properties in July 2013.

(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 June 30, 2013, early termination of the remaining contracts would require termination penalties of $104.9 million, which would be in lieu of paying the remaining drilling commitments of $140.7 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.

Table of Contents

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.

Effects of Inflation and Pricing

We experienced increased costs during 2012 and the first half 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 the Private Securities Litigation Reform Act of 1995. 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 “sho 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.

Table of Contents

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 our Annual Report on Form 10-K for the period ended December 31, 2012. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Quarterly Report on Form 10-Q.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and 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

Commodity Derivative Contracts—Our outstanding hedges as of July 15, 2013 are summarized below:

Whiting Petroleum Corporation

Derivative Instrument	Commodity	Period	Average Monthly Volume (Bbl)	Weighted Average NYMEX Price
Collars	Crude Oil	07/2013 to 09/2013	290,000	$47.67/$90.21
	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	07/2013 to 09/2013	1,040,000	$71.25/$85.63/$113.95
	Crude Oil	10/2013 to 12/2013	1,040,000	$71.25/$85.63/$113.95
	Crude Oil	01/2014 to 03/2014	800,000	$71.50/$85.00/$101.91
	Crude Oil	04/2014 to 06/2014	800,000	$71.50/$85.00/$101.91
	Crude Oil	07/2014 to 09/2014	800,000	$71.50/$85.00/$101.91
	Crude Oil	10/2014 to 12/2014	800,000	$71.50/$85.00/$101.91

(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 July 15, 2013 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	07/2013 to 09/2013	368,000	$5.47
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 757 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.

Table of Contents

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	07/2013 to 09/2013	44,500	$80.00/$122.50
	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 June 30, 2013, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of June 30, 2013 would cause a decrease or increase, respectively, of $46.1 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 June 30, 2013 would cause a decrease or increase, respectively, of $12.9 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 June 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 June 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.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended June 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

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2012. No material change to such risk factors has occurred during the six months ended June 30, 2013.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

After Whiting's announcement on June 17, 2013 to mandatorily convert all outstanding shares of its 6.25% convertible perpetual preferred stock (the "Preferred Stock"), Whiting issued 620,450 shares of its common stock upon the holders' voluntary conversion of 134,689 shares of Preferred Stock. On June 27, 2013, as a result of Whiting exercising its right to mandatorily convert all outstanding shares of Preferred Stock, Whiting issued 172,469 shares of its common stock upon the conversion of 37,440 shares of Preferred Stock. As a result of such conversions, there are no shares of Preferred Stock outstanding. The issuance of such shares qualified for the exemption provided by Section 3(a)(9) of the Securities Act of 1933, as amended. Whiting received no additional consideration for the issuance of its shares of common stock.

Item 5. Other Information

On January 1, 2013, Whiting adopted 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, Derivative and Hedging, including bifurcated embedded derivatives, repurchase agreements and reverse purchase 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 retrospective application did not have an impact on the Company's consolidated financial statements other than additional disclosures.

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 tables below reflect the unaudited retrospective application of ASU 2011-11 and ASU 2013-01 for the years ended December 31, 2012 and 2011, including 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

		December 31, 2012(1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	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

		December 31, 2011(1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 19,276	$ (13,557)	$ 5,719
Embedded commodity contracts	Prepaid expenses and other	240	-	240
Commodity contracts	Other long-term assets	3,209	(3,209)	-
Embedded commodity contracts	Other long-term assets	13,347	-	13,347
Total derivative assets		$ 36,072	$ (16,766)	$ 19,306
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 87,204	$ (13,557)	$ 73,647
Commodity contracts	Non-current derivative liabilities	50,972	(3,209)	47,763
Total derivative liabilities		$ 138,176	$ (16,766)	$ 121,410

(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.

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 26th day of July, 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
(3.1)	Restated Certificate of Incorporation of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.2 to Whiting Petroleum Corporation's Current Report on Form 8-K dated June 28, 2013 (File No. 001-31899)].
(4.1)	Fourth Amendment to Fifth Amended and Restated Credit Agreement, dated as of June 27, 2013, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto.
(10.1)	Whiting Petroleum Corporation 2013 Equity Incentive Plan [Incorporated by reference to Annex A to Whiting Petroleum Corporation's definitive proxy statement filed with the Securities and Exchange Commission on Schedule 14A on March 25, 2013 (File No. 001-31899)].
(10.2)	Noncompetition Agreement, between J. Douglas Lang and Whiting Petroleum Corporation, effective as of June 17, 2013 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated June 17, 2013 (File No. 001-31899)].
(10.3)	Purchase and Sale Agreement, by and between Whiting Oil and Gas Corporation and BreitBurn Operating L.P., effective as of April 1, 2013 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated June 22, 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 June 30, 2013 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of June 30, 2013 and December 31, 2012, (ii) the Consolidated Statements of Income for the Three and Six Months Ended June 30, 2013 and 2012, (iii) the Consolidated Statements of Comprehensive Income for the Three and Six Months Ended June 30, 2013 and 2012, (iv) the Consolidated Statements of Cash Flows for the Six Months Ended June 30, 2013 and 2012, (v) the Consolidated Statements of Equity for the Six Months Ended June 30, 2013 and 2012 and (vi) Notes to Consolidated Financial Statements.