WHITING PETROLEUM CORP
Form 10-Q
October 25, 2012

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

FORM 10-Q

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

For the quarterly period ended September 30, 2012

or

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

For the transition period from _______________ to _______________

Commission file number: 001-31899

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

Delaware (State or other jurisdiction of incorporation or organization)	20-0098515 (I.R.S. Employer Identification No.)
1700 Broadway, Suite 2300 Denver, Colorado (Address of principal executive offices)	80290-2300 (Zip code)

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

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

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

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

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

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

Number of shares of the registrant’s common stock outstanding at October 15, 2012: 117,631,451 shares.

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GLOSSARY OF CERTAIN DEFINITIONS

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

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

"Bcf" One billion cubic feet of natural gas.

"BOE" One stock tank barrel equivalent of oil, calculated by converting natural gas volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

"EBITDAX" Earnings before interest, income taxes, depreciation, depletion, amortization and exploration expense.

"FASB" Financial Accounting Standards Board.

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

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

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

"MBOE" One thousand BOE.

"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.

"NGL" Natural gas liquid.

"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.

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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.

"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.

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PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

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

	September 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 26,075	$ 15,811
Accounts receivable trade, net	345,352	262,515
Prepaid expenses and other	21,075	20,377
Total current assets	392,502	298,703
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	8,317,199	7,221,550
Unproved properties	366,255	354,774
Other property and equipment	152,786	150,933
Total property and equipment	8,836,240	7,727,257
Less accumulated depreciation, depletion and amortization	(2,416,815)	(2,088,517)
Total property and equipment, net	6,419,425	5,638,740
Debt issuance costs	27,945	33,306
Other long-term assets	89,578	74,860
TOTAL ASSETS	$ 6,929,450	$ 6,045,609
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 141,326	$ 56,673
Accrued capital expenditures	112,137	142,827
Accrued liabilities and other	175,104	157,214
Revenues and royalties payable	137,162	103,894
Taxes payable	42,380	31,195
Derivative liabilities	33,499	73,647
Deferred income taxes	10,967	1,584
Total current liabilities	652,575	567,034
Long-term debt	1,600,000	1,380,000
Deferred income taxes	1,012,286	823,643
Derivative liabilities	7,931	47,763
Production Participation Plan liability	86,858	80,659
Asset retirement obligations	57,183	61,984
Deferred gain on sale	117,946	29,619
Other long-term liabilities	27,577	25,776
Total liabilities	3,562,356	3,016,478
Commitments and contingencies		
Equity:		

Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 172,391 shares issued and outstanding as of September 30, 2012 and December 31, 2011, aggregate liquidation preference of $17,239,100 at September 30, 2012		-			-
Common stock, $0.001 par value, 300,000,000 shares authorized; 118,584,188 issued and 117,631,451 outstanding as of September 30, 2012, 118,105,279 issued and 117,380,884 outstanding as of December 31, 2011		119			118
Additional paid-in capital		1,562,025			1,554,223
Accumulated other comprehensive income (loss)		(1,202	)		240
Retained earnings		1,797,954			1,466,276
Total Whiting shareholders’ equity		3,358,896			3,020,857
Noncontrolling interest		8,198			8,274
Total equity		3,367,094			3,029,131
TOTAL LIABILITIES AND EQUITY	$	6,929,450		$	6,045,609

See notes to consolidated financial statements.

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 521,195	$ 468,573	$ 1,572,648	$ 1,368,121
Gain on hedging activities	398	1,871	2,285	7,326
Amortization of deferred gain on sale	8,636	3,518	21,281	10,455
Gain (loss) on sale of properties	99	13,505	(263)	14,732
Interest income and other	154	90	412	351
Total revenues and other income	530,482	487,557	1,596,363	1,400,985
COSTS AND EXPENSES:				
Lease operating	93,859	77,630	278,153	222,937
Production taxes	43,519	34,510	128,893	100,412
Depreciation, depletion and amortization	179,587	122,890	496,296	340,868
Exploration and impairment	23,882	18,918	79,362	61,326
General and administrative	25,034	23,144	84,611	62,470
Interest expense	18,734	16,130	55,095	45,867
Change in Production Participation Plan liability	6,217	853	6,199	3,060
Commodity derivative (gain) loss, net	6,421	(138,892)	(64,200)	(118,071)
Total costs and expenses	397,253	155,183	1,064,409	718,869
INCOME BEFORE INCOME TAXES	133,229	332,374	531,954	682,116
INCOME TAX EXPENSE (BENEFIT):				
Current	(1,859)	975	676	4,590
Deferred	51,975	125,164	198,868	248,728
Total income tax expense	50,116	126,139	199,544	253,318
NET INCOME	83,113	206,235	332,410	428,798
Net loss attributable to noncontrolling interest	21	-	76	-
NET INCOME AVAILABLE TO SHAREHOLDERS	83,134	206,235	332,486	428,798
Preferred stock dividends	(269)	(269)	(808)	(808)

NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 82,865	$ 205,966	$ 331,678	$ 427,990
EARNINGS PER COMMON SHARE:				
Basic	$ 0.70	$ 1.75	$ 2.82	$ 3.65
Diluted	$ 0.70	$ 1.74	$ 2.79	$ 3.62
WEIGHTED AVERAGE SHARES OUTSTANDING:				
Basic	117,631	117,381	117,590	117,333
Diluted	118,924	118,539	118,968	118,572

See notes to consolidated financial statements.

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
NET INCOME	$ 83,113	$ 206,235	$ 332,410	$ 428,798
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:				
OCI amortization on de-designated hedges(1)	(251)	(1,181)	(1,442)	(4,624)
Total other comprehensive loss, net of tax	(251)	(1,181)	(1,442)	(4,624)
COMPREHENSIVE INCOME	82,862	205,054	330,968	424,174
Comprehensive loss attributable to noncontrolling interest	21	-	76	-
COMPREHENSIVE INCOME ATTRIBUTABLE TO WHITING	$ 82,883	$ 205,054	$ 331,044	$ 424,174

(1) Presented net of income tax expense of $147 and $690 for the three months ended September 30, 2012 and 2011, respectively, and $843 and $2,702 for the nine months ended September 30, 2012 and 2011, respectively.

See notes to consolidated financial statements.

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

	Nine Months Ended September 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 332,410	$ 428,798
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	496,296	340,868
Deferred income tax expense	198,868	248,728
Amortization of debt issuance costs and debt discount	7,051	6,357
Stock-based compensation	13,498	10,086
Amortization of deferred gain on sale	(21,281)	(10,455)
(Gain) loss on sale of properties	263	(14,732)
Undeveloped leasehold and oil and gas property impairments	45,770	24,920
Exploratory dry hole costs	2,140	4,714
Change in Production Participation Plan liability	6,199	3,060
Unrealized gain on derivative contracts	(91,763)	(151,047)
Other, net	(14,311)	(8,285)
Changes in current assets and liabilities:		
Accounts receivable trade	(82,837)	(31,229)
Prepaid expenses and other	664	61
Accounts payable trade and accrued liabilities	80,525	(13,999)
Revenues and royalties payable	33,268	22,061
Taxes payable	11,185	3,848
Net cash provided by operating activities	1,017,945	863,754
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(102,978)	(233,521)
Drilling and development capital expenditures	(1,509,582)	(1,077,605)
Proceeds from sale of oil and gas properties	69,190	69,246
Issuance of note receivable	-	(25,000)
Net proceeds from sale of 18,400,000 units in Whiting USA Trust II	322,212	-
Net cash used in investing activities	(1,221,158)	(1,266,880)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Contributions from noncontrolling interest	-	2,500
Preferred stock dividends paid	(808)	(808)
Long-term borrowings under credit agreement	1,750,000	1,380,000
Repayments of long-term borrowings under credit agreement	(1,530,000)	(980,000)
Debt issuance costs	(20)	(2,381)
Restricted stock used for tax withholdings	(5,695)	(9,049)
Net cash provided by financing activities	213,477	390,262
NET CHANGE IN CASH AND CASH EQUIVALENTS	10,264	(12,864)

CASH AND CASH EQUIVALENTS:				
Beginning of period		15,811		18,952
End of period	$	26,075	$	6,088

See notes to consolidated financial statements. (Continued)

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

	Nine Months Ended September 30,	
	2012	2011
NONCASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 112,137	$ 112,526
NONCASH FINANCING ACTIVITIES:		
Contributions from noncontrolling interest	$ -	$ 5,833

See notes to consolidated financial statements. (Concluded)

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

	Preferred Stock		Common Stock		Additional Paid-in	Accumulated Other Comprehensive Income (Loss)	Retained	Total Whiting Shareholders'	Noncontrolling	Total
	Shares	Amount	Shares	Amount	Capital		Earnings	Equity	Interest	Equity
BALANCES-January 1, 2011	173	$-	117,968	$59	$1,549,822	$5,768	$975,666	$2,531,315	$-	$2,531,315
Net income	-	-	-	-	-	-	428,798	428,798	-	428,798
Other comprehensive income	-	-	-	-	-	(4,624)	-	(4,624)	-	(4,624)
Conversion of preferred stock to common	(1)	-	1	-	-	-	-	-	-	-
Two-for-one stock split	-	-	-	59	(59)	-	-	-	-	-
Contributions from noncontrolling interest	-	-	-	-	-	-	-	-	8,333	8,333
Restricted stock issued	-	-	304	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(16)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(148)	-	(9,049)	-	-	(9,049)	-	(9,049)
Stock-based compensation	-	-	-	-	10,086	-	-	10,086	-	10,086
Preferred dividends paid	-	-	-	-	-	-	(808)	(808)	-	(808)
BALANCES-September 30, 2011	172	$-	118,109	$118	$1,550,800	$1,144	$1,403,656	$2,955,718	$8,333	$2,964,051
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	-	-	-	-	-	-	332,486	332,486	(76)	332,410
Other comprehensive income	-	-	-	-	-	(1,442)	-	(1,442)	-	(1,442)
Restricted stock issued	-	-	592	1	(1)	-	-	-	-	-
Restricted stock forfeited	-	-	(7)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(106)	-	(5,695)	-	-	(5,695)	-	(5,695)
Stock-based compensation	-	-	-	-	13,498	-	-	13,498	-	13,498
Preferred dividends paid	-	-	-	-	-	-	(808)	(808)	-	(808)
BALANCES-September 30, 2012	172	$-	118,584	$119	$1,562,025	$(1,202)	$1,797,954	$3,358,896	$8,198	$3,367,094

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS (Unaudited)

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, natural gas and natural gas liquids 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 2011 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 2011 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

2012 Acquisition

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.

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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 $322.2 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 18,400,000 trust 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.

2011 Acquisitions

On July 28, 2011, the Company completed the acquisition of approximately 23,400 net acres and one well in the Missouri Breaks prospect in Richland County, Montana for an unadjusted purchase price of $46.9 million. Disclosures of pro forma revenues and net income for the acquisition of this one well are not material and have not been presented accordingly.

On March 18, 2011, Whiting and an unrelated third party formed Sustainable Water Resources, LLC ("SWR") to develop a water project in the state of Colorado. The Company contributed $25.0 million for a 75% interest in SWR, and the 25% noncontrolling interest in SWR was ascribed a fair value of $8.3 million, which consisted of $2.5 million in cash contributions, as well as $5.8 million in intangible and fixed assets contributed to the joint venture.

On February 15, 2011, the Company completed the acquisition of 6,000 net undeveloped acres and additional working interests in the Pronghorn field in the Billings and Stark counties of North Dakota, for an aggregate purchase price of $40.0 million.

2011 Divestiture

On September 29, 2011, Whiting sold its interest in several non-core oil and gas producing properties located in the Karnes, Live Oak and DeWitt counties of Texas for total cash proceeds of $64.8 million, resulting in a pre-tax gain on sale of $12.3 million. Whiting used the net proceeds from the property sale to repay a portion of the debt outstanding under its credit agreement.

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3. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2012 and December 31, 2011 (in thousands):

	September 30, 2012	December 31, 2011
Credit agreement	$1,000,000	$780,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
7% Senior Subordinated Notes due 2014	250,000	250,000
Total debt	$1,600,000	$1,380,000

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 September 30, 2012, this credit facility had a borrowing base of $1.5 billion with $497.6 million of available borrowing capacity, which is net of $1.0 billion in borrowings and $2.4 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2016, when the agreement expires and all outstanding borrowings are due. In October 2012, Whiting Oil and Gas entered into an amendment to its existing credit agreement that increased the borrowing base under the facility from $1.5 billion to $2.5 billion, of which $2.0 billion has been committed by lenders and is available for borrowing. Whiting Oil and Gas may increase the maximum aggregate amount of commitments under the credit agreement from $2.0 billion to $2.5 billion if certain conditions are satisfied, including the consent of lenders participating in the increase.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company's proved reserves that have been mortgaged to its lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of September 30, 2012, $47.6 million was available for additional letters of credit under the agreement.

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 are included as a component of interest expense. At September 30, 2012, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.2%.

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, which include the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement also restricts the Company's ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the net assets of Whiting Oil and Gas. As of September 30, 2012, total restricted net assets were $3,343.2 million, and the amount of retained earnings free from restrictions was $19.1 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 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for the quarters ending March 31, 2013 and thereafter and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. The Company was in compliance with its covenants under the credit agreement as of September 30, 2012.

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The obligations of Whiting Oil and Gas under the amended 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 $266.6 million as of September 30, 2012, 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 $377.1 million as of September 30, 2012, based on quoted market prices for these debt securities, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

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 Securities and Exchange Commission. 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 estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws. The Company follows FASB ASC Topic 410, Asset Retirement and Environmental Obligations, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The current portions at September 30, 2012 and December 31, 2011 were $11.2 million and $7.7 million, respectively, and are included in accrued liabilities and other. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells. The following table provides a reconciliation of the Company's asset retirement obligations for the nine months ended September 30, 2012 (in thousands):

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Asset retirement obligation at January 1, 2012	$69,721
Additional liability incurred	6,233
Revisions in estimated cash flows	(4,335)
Accretion expense	5,339
Obligations on sold properties	(4)
Liabilities settled	(8,588)
Asset retirement obligation at September 30, 2012	$68,366

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, 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 and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not enter into derivative contracts for speculative or trading purposes.

Whiting Derivatives. The table below details the Company's costless collar derivatives, including its proportionate share of Trust I and Trust II derivatives, entered into to hedge forecasted crude oil and natural gas production revenues, as of October 1, 2012.

		Whiting Petroleum Corporation			
		Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Derivative Instrument	Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Collars	Oct – Dec 2012	3,489,470	91,921	$ 68.94 - $ 106.81	$ 7.00 - $ 13.40
	Jan – Dec 2013	3,143,700	-	$ 48.20 - $ 90.45	n/a
	Jan – Dec 2014	49,290	-	$ 80.00 - $ 122.50	n/a
Three-way collars(1)	Jan – Dec 2013	10,920,000	-	$ 70.00 - $ 85.00 - $ 114.80	n/a
	Total	17,602,460	91,921		

(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.

Derivatives Conveyed to Whiting USA Trust I. In connection with the Company's conveyance in April 2008 of a term net profits interest to Trust I and related sale of 11,677,500 Trust I 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 I, and therefore such payments will be included in Trust I's calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties. Whiting's retention of 10% of these net proceeds, combined with its ownership of 2,186,389 Trust I units, results in third-party public holders of Trust I units receiving 75.8%, and Whiting retaining 24.2%, of the future economic results of commodity derivative contracts conveyed to Trust I. 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 I assets.

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The 24.2% portion of Trust I derivatives that Whiting has retained the economic rights to (and which are also included in the table above) are as follows:

		Whiting Petroleum Corporation			
		Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Derivative Instrument	Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Collars	Oct – Dec 2012	25,430	91,921	$ 74.00 - $ 142.21	$ 7.00 - $ 13.40

The 75.8% portion of Trust I derivative contracts of which Whiting has transferred the economic rights to third-party public holders of Trust I units (and which have not been reflected in the above tables) are as follows:

		Third-party Public Holders of Trust I Units			
		Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Derivative Instrument	Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Collars	Oct – Dec 2012	79,654	287,918	$ 74.00 - $ 142.21	$ 7.00 - $ 13.40

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	Oct – Dec 2012	14,040	$ 80.00 - $ 122.50
	Jan – Dec 2013	53,700	$ 80.00 - $ 122.50
	Jan – Dec 2014	49,290	$ 80.00 - $ 122.50
	Total	117,030	

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:

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		Third-party Public Holders of Trust II Units	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Oct – Dec 2012	126,360	$ 80.00 - $ 122.50
	Jan – Dec 2013	483,300	$ 80.00 - $ 122.50
	Jan – Dec 2014	443,610	$ 80.00 - $ 122.50
	Total	1,053,270	

Embedded Commodity Derivative Contracts—As of September 30, 2012, Whiting had entered into certain contracts for oil field goods or services, whereby the price adjustment clauses for such goods or services are linked to changes in NYMEX crude oil prices. The Company has determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host contracts, and the Company has therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in the consolidated financial statements.

Drilling Rig Contracts. As of September 30, 2012, Whiting had entered into two contracts with drilling rig companies, whereby the rig day rates included price adjustment clauses that are linked to changes in NYMEX crude oil prices. These drilling rig contracts have termination dates of April 2014 and September 2014. The price adjustment formulas in the rig contracts stipulate that with every $10 increase or decrease in the price of NYMEX crude, the cost of drilling rig day rates to the Company will likewise increase or decrease by specific dollar amounts as set forth in each of the individual contracts. As of September 30, 2012, the aggregate estimated fair value of the embedded derivatives in these drilling rig contracts was zero. This is because over the remaining period of each contract's term, the prices on the forward curve for crude oil at September 30, 2012 were within $10 of the prices on the forward curve on the date the contracts were executed, which leads to no change in the expected drilling costs under these contracts and therefore no change in contractual value from the execution date.

As global crude oil prices increase or decrease, the demand for drilling rigs in North America similarly increases and decreases. Because the supply of onshore drilling rigs in North America is fairly inelastic, these changes in rig demand cause drilling rig day rates to increase or decrease in tandem with crude oil price fluctuations. When the Company enters into a long-term drilling rig contract that has a fixed rig day rate, which does not increase or decrease with changes in oil prices, the Company is exposed to the risk of paying higher than the market day rate for drilling rigs in a climate of declining oil prices. This in turn could have a negative impact on the Company's oil and gas well economics. As a result, the Company reduces its exposure to this risk by entering into certain drilling contracts which have day rates that fluctuate in tandem with changes in oil prices.

CO_2 Purchase Contract. In May 2011, Whiting entered into a long-term contract to purchase CO_2 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. 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. As of September 30, 2012, the estimated fair value of the embedded derivative in this CO_2 purchase contract was an asset of $18.1 million.

Although CO_2 is not a commodity that is actively traded on a public exchange, the market price for CO_2 generally fluctuates in tandem with increases or decreases in crude oil prices. When Whiting enters into a long-term CO_2 purchase contract where the price of CO_2 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 CO_2 in a climate of declining oil and CO_2 prices. This in turn could have a negative impact on the project economics of the Company's CO_2 flood at North Ward Estes. As a result, the Company reduces its exposure to this risk by entering into certain CO_2 purchase contracts which have prices that fluctuate along with changes in crude oil prices.

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Derivative Instrument Reporting—All derivative instruments are recorded on the consolidated balance sheet at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands):

Not Designated as ASC 815 Hedges	Balance Sheet Classification	Fair Value September 30, 2012	Fair Value December 31, 2011
Derivative assets:			
Commodity contracts	Prepaid expenses and other	$ 7,329	$ 5,719
Embedded commodity contracts	Prepaid expenses and other	-	240
Commodity contracts	Other long-term assets	3,518	-
Embedded commodity contracts	Other long-term assets	18,086	13,347
Total derivative assets		$ 28,933	$ 19,306
Derivative liabilities:			
Commodity contracts	Current derivative liabilities	$ 33,499	$ 73,647
Commodity contracts	Non-current derivative liabilities	7,931	47,763
Total derivative liabilities		$ 41,430	$ 121,410

The following tables summarize the effects of commodity derivatives instruments on the consolidated statements of income for the three and nine months ended September 30, 2012 and 2011 (in thousands):

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain Reclassified from OCI into Income (Effective Portion) Nine Months Ended September 30, 2012	2011
Commodity contracts	Gain on hedging activities	$ 2,285	$ 7,326

		Three Months Ended September 30, 2012	2011
Commodity contracts	Gain on hedging activities	$ 398	$ 1,871

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Nine Months Ended September 30, 2012	2011
Commodity contracts	Commodity derivative (gain) loss, net	$ (59,701)	$ (100,439)
Embedded commodity contracts	Commodity derivative (gain) loss, net	(4,499)	(17,632)
Total		$ (64,200)	$ (118,071)

		Three Months Ended September 30, 2012	Three Months Ended September 30, 2011
Commodity contracts	Commodity derivative (gain) loss, net	$ 5,985	$ (121,734)
Embedded commodity contracts	Commodity derivative (gain) loss, net	436	(17,158)
Total		$ 6,421	$ (138,892)

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. At the time Whiting enters into derivative contracts, 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.

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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.

The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2012 and December 31, 2011, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value September 30, 2012
Financial Assets				
Commodity derivatives – current	$ -	$ 7,329	$ -	$ 7,329
Commodity derivatives – non-current	-	3,518	-	3,518
Embedded commodity derivatives – non-current	-	-	18,086	18,086
Total financial assets	$ -	$ 10,847	$ 18,086	$ 28,933
Financial Liabilities				
Commodity derivatives – current	$ -	$ 33,499	$ -	$ 33,499
Commodity derivatives – non-current	-	7,931	-	7,931
Total financial liabilities	$ -	$ 41,430	$ -	$ 41,430

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	Level 1		Level 2		Level 3		Total Fair Value December 31, 2011	
Financial Assets								
Commodity derivatives – current	$	-	$	5,719	$	-	$	5,719
Embedded commodity derivatives – current		-		240		-		240
Embedded commodity derivatives – non-current		-		367		12,980		13,347
Total financial assets	$	-	$	6,326	$	12,980	$	19,306
Financial Liabilities								
Commodity derivatives – current	$	-	$	73,647	$	-	$	73,647
Commodity derivatives – non-current		-		47,763		-		47,763
Total financial liabilities	$	-	$	121,410	$	-	$	121,410

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 primarily of costless collars for crude oil and natural gas. The Company's costless collars are valued based on an income approach. These option models consider various assumptions, including 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. Embedded commodity derivatives relate to long-term drilling rig contracts as well as a long-term CO2 purchase contract, which all have price adjustment clauses that are linked to changes in NYMEX crude oil prices. Whiting has determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host drilling contracts, and the Company has therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in its consolidated financial statements. These embedded commodity derivatives are valued based on an income approach. These option models consider various assumptions, including quoted forward prices for commodities, LIBOR discount rates and either the Company's or the counterparty's nonperformance risk, as appropriate.

The assumptions used in the valuation of the drilling rig contracts 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 the fair value measurements of the drilling rig contracts are therefore designated as Level 2 within the valuation hierarchy.

The assumptions used in the CO2 contract valuation, however, 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 these valuations (including the related model inputs and assumptions) and analyzes changes in fair value measurements between periods. The Company corroborates such inputs, calculations and fair value changes using various methodologies, and Whiting reviews unobservable inputs for reasonableness utilizing relevant information from other published sources.

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The following table presents a reconciliation of changes in the fair value of financial assets (liabilities) designated as Level 3 in the valuation hierarchy for the three and nine months ended September 30, 2012 and 2011 (in thousands):

	Nine Months Ended September 30,	
	2012	2011
Fair value asset, beginning of period	$12,980	$-
Unrealized gains (losses) on embedded commodity derivative contracts included in earnings(1)	5,106	13,196
Transfers into (out of) Level 3(2)	-	1,899
Fair value asset, end of period	$18,086	$15,095

	Three Months Ended September 30,	
	2012	2011
Fair value asset, beginning of period	$17,678	$-
Unrealized gains (losses) on embedded commodity derivative contracts included in earnings(1)	408	13,196
Transfers into (out of) Level 3(2)	-	1,899
Fair value asset, end of period	$18,086	$15,095

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

(2) With respect to forward prices for NYMEX crude oil where there is a lack of price transparency in certain future periods during the term of the CO2 contract, such unobservable oil price inputs became significant to the valuation methodology, and the contract's fair value was therefore transferred from Level 2 to Level 3 within the valuation hierarchy during the third quarter of 2011.

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

	Fair Value at September 30, 2012 (in thousands)	Valuation Technique	Unobservable Input	Range (per Bbl)
Embedded commodity derivative	$18,086	Option model	Future prices of NYMEX crude oil after September 30, 2018	$89.24 - $123.64

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 October 2018 to 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 2012 or 2011 reporting periods presented.

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7. DEFERRED COMPENSATION

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

Payments of 100% of the year’s Plan interests to employees and the vested percentages of former employees in the year’s Plan interests are made annually in cash after year-end. Accrued compensation expense under the Plan for the nine months ended September 30, 2012 and 2011 amounted to $37.1 million and $27.6 million, respectively, charged to general and administrative expense and $3.9 million and $3.5 million, respectively, charged to exploration expense.

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

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At September 30, 2012, the Company used three-year average historical NYMEX prices of $87.18 for crude oil and $3.86 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control of the Company (as defined in the Plan), all employees fully vest and the Company would distribute to each Plan participant an amount, based upon the valuation method set forth in the Plan, in a lump sum payment twelve months after the date of termination or within one month after a change in control event. Based on current strip prices at September 30, 2012, 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 $172.9 million. This amount includes $13.4 million attributable to proved undeveloped oil and gas properties and $41.0 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2013. 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	$80,659
Change in liability for accretion, vesting, changes in estimates and new Plan year activity	47,190
Accrued compensation expense reflected as a current liability	(40,991)
Long-term Production Participation Plan liability at September 30	$86,858

8. SHAREHOLDERS’ EQUITY AND NONCONTROLLING INTEREST

Common Stock—In May 2011, Whiting’s stockholders approved an amendment to the Company’s Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 175,000,000 shares to 300,000,000 shares.

Stock Split. On January 26, 2011, the Company’s Board of Directors approved a two-for-one split of the Company's shares of common stock to be effected in the form of a stock dividend. As a result of the stock split, stockholders of record on February 7, 2011 received one additional share of common stock for each share of common stock held. The additional shares of common stock were distributed on February 22, 2011. Concurrently with the payment of such stock dividend in February 2011, there was a transfer from additional paid-in capital to common stock of $0.1 million, which amount represents $0.001 per share (being the par value thereof) for each share of common stock so issued. The common stock dividend resulted in the conversion price for Whiting's 6.25% Convertible Perpetual Preferred Stock being adjusted from $43.4163 to $21.70815.

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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 of September 30, 2012, however, only 172,391 shares of preferred stock remained outstanding.

Each holder of the preferred stock is 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 has been declared by Whiting's board of directors. Each share of preferred stock has a liquidation preference of $100.00 per share plus accumulated and unpaid dividends and is 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 is not redeemable by the Company. At any time on or after June 15, 2013, the Company may cause all outstanding shares of this preferred stock to be converted into shares of common stock if the closing price of our common stock equals or exceeds 120% of the then-prevailing conversion price for at least 20 trading days in a period of 30 consecutive trading days. The holders of preferred stock have no voting rights unless dividends payable on the preferred stock are in arrears for six or more quarterly periods.

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

	Nine Months Ended September 30,	
	2012	2011
Balance at January 1	$8,274	$-
Contributions from noncontrolling interest	-	8,333
Net income (loss)	(76)	-
Balance at September 30	$8,198	$8,333

9. INCOME TAXES

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The provision for income taxes for the three and nine months ended September 30, 2012 and 2011 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.

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10. EARNINGS PER SHARE

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

	Three Months Ended September 30,	
	2012	2011
Basic Earnings Per Share		
Numerator:		
Net income available to shareholders	$83,134	$206,235
Preferred stock dividends	(269)	(269)
Net income available to common shareholders, basic	$82,865	$205,966
Denominator:		
Weighted average shares outstanding, basic	117,631	117,381
Diluted Earnings Per Share		
Numerator:		
Net income available to common shareholders, basic	$82,865	$205,966
Preferred stock dividends	269	269
Adjusted net income available to common shareholders, diluted	$83,134	$206,235
Denominator:		
Weighted average shares outstanding, basic	117,631	117,381
Restricted stock and stock options	499	364
Convertible perpetual preferred stock	794	794
Weighted average shares outstanding, diluted	118,924	118,539
Earnings per common share, basic	$0.70	$1.75
Earnings per common share, diluted	$0.70	$1.74

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For the three months ended September 30, 2012, the diluted earnings per share calculation excludes the effect of 23,320 common shares for stock options that were out-of-the-money and 152,079 incremental common shares for restricted stock that did not meet its market-based vesting criteria as of September 30, 2012. For the three months ended September 30, 2011, the diluted earnings per share calculation excludes the effect of 27,769 common shares for stock options that were out-of-the-money and 152,229 incremental common shares for restricted stock that did not meet its market-based vesting criteria as of September 30, 2011.

	Nine Months Ended September 30, 2012	2011
Basic Earnings Per Share		
Numerator:		
Net income available to shareholders	$332,486	$428,798
Preferred stock dividends	(808)	(808)
Net income available to common shareholders, basic	$331,678	$427,990
Denominator:		
Weighted average shares outstanding, basic	117,590	117,333
Diluted Earnings Per Share		
Numerator:		
Net income available to common shareholders, basic	$331,678	$427,990
Preferred stock dividends	808	808
Adjusted net income available to common shareholders, diluted	$332,486	$428,798
Denominator:		
Weighted average shares outstanding, basic	117,590	117,333
Restricted stock and stock options	584	445
Convertible perpetual preferred stock	794	794
Weighted average shares outstanding, diluted	118,968	118,572
Earnings per common share, basic	$2.82	$3.65
Earnings per common share, diluted	$2.79	$3.62

For the nine months ended September 30, 2012, the diluted earnings per share calculation excludes the effect of 9,920 common shares for stock options that were out-of-the-money and 135,381 incremental common shares for restricted stock that did not meet its market-based vesting criteria as of September 30, 2012. For the nine months ended September 30, 2011, the diluted earnings per share calculation excludes the effect of 1,260 incremental common shares for stock options that were out-of-the-money and 174,814 incremental common shares for restricted stock that did not meet its market-based vesting criteria as of September 30, 2011.

11. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In May 2011, the FASB issued Accounting Standards Update No. 2011-04, Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU 2011-04"), which provides amendments to FASB ASC Topic 820, Fair Value Measurement. The objective of ASU 2011-04 is to create common fair value measurement and disclosure requirements between GAAP and International Financial Reporting Standards ("IFRS"). The amendments clarify existing fair value measurement and disclosure requirements and make changes to particular principles or requirements for measuring or disclosing information about fair value measurements. ASU 2011-04 was effective for interim and annual reporting periods beginning after December 15, 2011. The Company adopted this standard effective January 1, 2012, which did not have an impact on the Company's consolidated financial statements other than additional disclosures.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income: Presentation of Comprehensive Income (“ASU 2011-05”), which provides amendments to FASB ASC Topic 220, Comprehensive Income. The objective of ASU 2011-05 is to require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of equity. ASU 2011-05 is effective for interim and annual periods beginning after December 15, 2011 and is to be applied retrospectively. In December 2011, the FASB issued Accounting Standards Update No. 2011-12, Comprehensive Income: Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 (“ASU 2011-12”), which defers the effective date of changes in ASU 2011-05 that relate to the presentation of reclassification adjustments out of accumulated other comprehensive income. The amendments in this update are effective at the same time as the amendments in ASU 2011-05. The Company adopted the provisions of ASU 2011-05 and 2011-12 effective January 1, 2012, which did not have an impact on its consolidated financial statements other than requiring the Company to present its statements of comprehensive income separately from its statements of equity, as these statements were previously presented on a combined basis.

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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. ASU 2011-11 is effective for interim and annual reporting periods beginning on or after January 1, 2013 and should be applied retrospectively. The adoption of this standard will not have a significant impact on the Company's consolidated financial statements.

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 adoption of this standard will not have a significant impact on the Company's consolidated financial statements.

12. SUBSEQUENT EVENT

In October 2012, Whiting Oil and Gas entered into an amendment to its existing credit agreement that increased the Company's borrowing base under the facility from $1.5 billion to $2.5 billion, of which $2.0 billion has been committed by lenders and is available for borrowing. Whiting Oil and Gas may increase the maximum aggregate amount of commitments under the credit agreement from $2.0 billion to $2.5 billion if certain conditions are satisfied, including the consent of lenders participating in the increase. All other terms of the credit agreement remain unchanged.

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

Unless the context otherwise requires, the terms "Whiting," "we," "us," "our" or "ours" when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation 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 capital 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.

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 2010:

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	2010				2011				2012		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Crude Oil	$78.79	$77.99	$76.21	$85.18	$94.25	$102.55	$89.81	$94.02	$102.94	$93.51	$92.19
Natural Gas	$ 5.30	$ 4.09	$ 4.39	$ 3.81	$ 4.10	$ 4.32	$ 4.20	$ 3.54	$ 2.72	$ 2.21	$ 2.81

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 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.

2012 Highlights and Future Considerations

Operational Highlights.

Sanish. Our Sanish field in Mountrail County, North Dakota targets the Bakken and Three Forks formations. Net production in the Sanish field averaged 31.4 MBOE/d for the third quarter of 2012, which represents a slight decrease from 31.5 MBOE/d during the second quarter of 2012.

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. Net production in the Lewis & Clark/Pronghorn prospects averaged 12.2 MBOE/d in the third quarter of 2012, representing a 19% increase from 10.3 MBOE/d in the second quarter of 2012.

In December 2011, we substantially completed the construction of our gas processing plant located south of Belfield, North Dakota, which will have a processing capacity of 30 MMcf/d and which will primarily process production from the Pronghorn area. Currently, there is inlet compression in place to process 24 MMcf/d, and as of September 30, 2012, the plant was processing 12 MMcf/d. We expect to begin connecting other operators' wells to the plant in the fourth quarter of 2012. 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.

Hidden Bench/Tarpon. Our Hidden Bench and Tarpon prospects in McKenzie County, North Dakota target the Bakken and Three Forks formations. In the third quarter of 2012, production from the Hidden Bench/Tarpon prospects averaged 2.5 MBOE/d, representing a 14% increase from 2.2 MBOE/d in the second quarter of 2012.

Big Island. We have identified more than 50 vertical Red River prospects at our Big Island play in Golden Valley County, North Dakota and Wibaux County, Montana using 3-D seismic interpretations as well as porosity anomalies.

North Ward Estes. The North Ward Estes field is located in the Ward and Winkler counties in 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 CO_2 flood in this area continues to generate positive results.

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North Ward Estes has generally 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 we anticipate a production response in early 2013. Net production from North Ward Estes averaged 8.5 MBOE/d for the third quarter of 2012, which represents a 2% decrease from 8.6 MBOE/d in the second quarter of 2012. We are currently injecting approximately 340 MMcf/d of CO2 into the field, over half of which is recycled.

Postle. The Postle field is located in Texas County, Oklahoma and produces from the Morrow sandstone. Postle averaged 8.2 MBOE/d in the third quarter of 2012, which was consistent with production rates in the second quarter of 2012. We are currently injecting approximately 130 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. We have increased our planned capital expenditures and drilling activity in the Big Tex prospect from a 13-well drilling program to a 17-well program. These wells will be a mixture of vertical Wolfcamp and Wolfbone wells, horizontal Wolfcamp wells and horizontal Bone Spring wells. We currently have two horizontal Wolfcamp wells awaiting completion.

Redtail. Our Redtail prospect located in the Denver Julesberg Basin in Weld County, Colorado targets the Niobrara formation. In late 2010, we initiated a seven-well exploratory drilling program (five horizontal and two vertical monitor wells) in the Niobrara formation. Based on the results of our exploratory drilling program and recently acquired 3-D seismic data, we initiated a 17-well drilling program in this area in 2012. During the first nine months of 2012, our drilling was primarily focused on the Niobrara "B" zone, and we plan to target the Niobrara "A" zone during the fourth quarter of 2012. We currently have two Niobrara "A" zone wells awaiting completion.

Acquisition and Divestiture Highlights. On May 18, 2012, we sold a 50% ownership interest in our 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. We used the net proceeds from the sale to repay a portion of the debt outstanding under our credit agreement.

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

Whiting USA Trust II. On March 28, 2012, we 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 $322.2 million after underwriters' fees, offering expenses and post-close adjustments. We used the net offering proceeds to repay a portion of the debt outstanding under our 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, we conveyed a term net profits interest in certain of our oil and gas properties to Trust II in exchange for 18,400,000 trust 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 our proved reserves as of December 31, 2011 and 5% (or 4.5 MBOE/d) of our March 2012 average daily net production.

Financing Highlights. In October 2012, we entered into an amendment to our existing credit agreement that increased our borrowing base under the facility from $1.5 billion to $2.5 billion, of which $2.0 billion has been committed by lenders and is available for borrowing. We may increase the maximum aggregate amount of commitments under the credit agreement from $2.0 billion to $2.5 billion if certain conditions are satisfied, including the consent of lenders participating in the increase. All other terms of the credit agreement remain unchanged.

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Results of Operations

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net production:		
Oil (MMBbl)	17.0	13.4
NGLs (MMBOE)	2.1	1.5
Natural gas (Bcf)	19.3	20.1
Total production (MMBOE)	22.3	18.3
Net sales (in millions):		
Oil (1)	$1,429.5	$1,185.6
NGLs	78.2	82.4
Natural gas (1)	64.9	100.1
Total oil and natural gas sales	$1,572.6	$1,368.1
Average sales prices:		
Oil (per Bbl)	$83.99	$88.52
Effect of oil hedges on average price (per Bbl)	(1.55)	(1.97)
Oil net of hedging (per Bbl)	$82.44	$86.55
Average NYMEX price (per Bbl)	$96.20	$95.52
NGLs (per BOE)	$38.06	$53.75
Natural gas (per Mcf)	$3.36	$4.98
Effect of natural gas hedges on average price (per Mcf)	0.06	0.03
Natural gas net of hedging (per Mcf)	$3.42	$5.01
Average NYMEX price (per Mcf)	$2.58	$4.21
Cost and expenses (per BOE):		
Lease operating expenses	$12.48	$12.20
Production taxes	$5.78	$5.49
Depreciation, depletion and amortization expense	$22.26	$18.65
General and administrative expenses	$3.80	$3.42

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $204.5 million to $1,572.6 million for the first nine months of 2012 compared to the same period in 2011. Sales revenue is a function of oil and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 27% and our NGL sales volumes increased 34% between periods, while our natural gas sales volumes decreased 4%. The oil volume increase resulted primarily from drilling success at our Sanish field, Lewis & Clark/Pronghorn prospects and our Hidden Bench prospect. During the first nine months of 2012, oil production from our Sanish field increased 1,740 MBbl, while oil production from our Lewis & Clark/Pronghorn prospects increased 1,670 MBbl compared to the first nine months of 2011, and oil production from our Hidden Bench prospect increased 420 MBbl over the same period in 2011. These production increases were partially offset by the Trust II divestiture, which decreased oil production by 595 MBOE thus far in 2012. 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. As a result, our NGL sales volume increases generally relate to the same areas as our oil volume increases, such as our Sanish field, Lewis &

Clark/Pronghorn prospects and our Hidden Bench prospect. The gas volume decline between periods was primarily the result of normal field production decline across several areas, as well as the Trust II divestiture. During the first nine months of 2012, gas production at our Flat Rock field decreased 1,390 MMcf, and gas production at our Canyon field decreased 625 MMcf compared to the first nine months of 2011. The Trust II divestiture in March 2012 negatively impacted gas production by 1,195 MMcf during the nine month period ended September 30, 2012. These gas volume declines were partially offset by increases in associated gas production of 1,405 MMcf at our Lewis & Clark/Pronghorn prospects and 1,045 MMcf at our Sanish field, related to new wells drilled and completed in these areas during the past twelve months.

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Partially offsetting the above production-related increases in net revenue, were decreases in the average sales prices realized for oil, NGLs and natural gas. Our average price for oil before the effects of hedging decreased 5% for the first nine months of 2012 as compared to the first nine months of 2011, while our average price for NGLs decreased 29%, and our average price for natural gas before the effects of hedging decreased 33% between periods.

Gain (Loss) on Hedging Activities. Our gain on hedging activities decreased $5.0 million in 2012 as compared to the first nine months of 2011, and it consisted of the following (in thousands):

	Nine Months Ended September 30,	
	2012	2011
Gains reclassified from AOCI on de-designated hedges	$2,285	$7,326

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 as gain on hedging activities.

See Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding oil and natural gas derivatives as of October 1, 2012.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during the first nine months of 2012 were $278.2 million, a $55.2 million increase over the same period in 2011. This rise in LOE in 2012 was primarily related to a $53.5 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. In addition, well workover activity increased to $65.0 million in the first nine months of 2012, as compared to $63.3 million in the first nine months of 2011, primarily due to a higher number of workovers being conducted at our Sanish field. This increase in workover expense was partially offset by decreases in the number of workovers being conducted at our two main CO_2 projects.

Our lease operating expenses on a BOE basis also increased during the first nine months of 2012. LOE per BOE amounted to $12.48 for the first nine months of 2012, which was up from $12.20 per BOE for the first nine months of 2011. This increase was mainly due to the higher costs of oil field goods and services, plant expenses and workover activity in 2012, as discussed above, which were largely offset by higher overall production volumes between periods.

Production Taxes. Our production taxes during the first nine months of 2012 were $128.9 million, a $28.5 million increase over the same period in 2011, which increase was primarily due to higher oil and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.2% and 7.3% for the first nine months of 2012 and 2011, respectively. Our production tax rate for the first nine months of 2012 was greater than the rate for the same period in 2011 due to successful wells completed during the past twelve months in North Dakota, which has an 11.5% production tax rate. In addition, we take advantage of credits and exemptions allowed in our various taxing jurisdictions.

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Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $155.4 million in 2012 as compared to the first nine months of 2011. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2012	2011
Depletion	$488,333	$333,010
Depreciation	2,624	1,910
Accretion of asset retirement obligations	5,339	5,948
Total	$496,296	$340,868

DD&A increased in the first nine months of 2012 primarily due to $155.3 million in higher depletion expense between periods. This increase was the result of $87.9 million in higher depletion due to a rise in overall production volumes during the first nine months of 2012 and $67.4 million in higher depletion due to an increase in our depletion rate between periods. On a BOE basis, our DD&A rate of $22.26 for the first nine months of 2012 was 19% higher than the rate of $18.65 for the same period in 2011. The higher DD&A rate was mainly due to $1,917.7 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 $18.0 million in the first nine months of 2012 as compared to the first nine months of 2011. The components of our exploration and impairment costs were as follows (in thousands):

	Nine Months Ended September 30,	
	2012	2011
Exploration	$33,592	$36,406
Impairment	45,770	24,920
Total	$79,362	$61,326

Exploration costs decreased $2.8 million during the first nine months of 2012 as compared to the same period in 2011 primarily due to lower exploratory dry hole costs and a decrease in geological and geophysical ("G&G") activity. Exploratory dry hole costs for the nine months ended September 30, 2012 totaled $2.1 million, primarily related to one exploratory dry hole drilled in the Rocky Mountains region during the third quarter of 2012. During the first nine months of 2011, we drilled three exploratory dry holes in the Rocky Mountains, Permian Basin and Gulf Coast regions totaling $4.7 million. G&G costs, such as seismic studies, amounted to $13.3 million during the first nine months of 2012 as compared to $15.3 million during the same period in 2011. These decreases in exploration costs were partially offset by an increase of $1.1 million in geology-related general and administrative expenses during the first nine months of 2012.

Impairment expense in the first nine months of 2012 and 2011 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $40.2 million for the first nine months of 2012 as compared to $24.6 million for the first nine months of 2011. In addition, acreage costs of $5.6 million were written-off to impairment expense in the first nine months of 2012 for leases that had reached their expiration dates but where no wells had been drilled on such acreage.

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

	Nine Months Ended September 30,	
	2012	2011
General and administrative expenses	$151,329	$112,444
Reimbursements and allocations	(66,718)	(49,974)
General and administrative expense, net	$84,611	$62,470

General and administrative expense before reimbursements and allocations increased $38.9 million during the first nine months of 2012 as compared to the same period in 2011 primarily due to higher employee compensation, an increase in accrued Production Participation Plan (the "Plan") distributions and a $5.9 million increase in professional fees and information technology costs. Employee compensation increased $17.8 million in the first nine months of 2012 as compared to the first nine months of 2011 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. In addition, accrued distributions under the Plan increased general and administrative expenses by $9.5 million when comparing the first nine months of 2012 to the same period in 2011. Of this increase in general and administrative expenses related to Plan distributions, $8.6 million related to the Trust II net profits interest divestiture, and $0.9 million related to a higher level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula).

The increase in reimbursements and allocations for the first nine months of 2012 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales remained constant at 5% for the first nine months of 2011 and 2012.

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

	Nine Months Ended September 30,	
	2012	2011
Senior Subordinated Notes	$30,188	$30,188
Credit agreement	19,958	11,619
Amortization of debt issue costs and debt discount	7,051	6,357
Other	104	101
Capitalized interest	(2,206)	(2,398)
Total	$55,095	$45,867

The increase in interest expense of $9.2 million between periods was mainly attributable to a $8.3 million increase in the amount of interest incurred on our credit agreement during the first nine months of 2012 as compared to the first nine months of 2011. Our credit agreement interest was higher in 2012 due to a greater amount of borrowings outstanding under this facility. Our weighted average debt outstanding during the first nine months of 2012 was $1,502.0 million versus $1,087.4 million for the first nine months of 2011. Our weighted average effective cash interest rate was 4.5% during the first nine months of 2012 compared to 5.1% during the first nine months of 2011.

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 only cash settlement gains and losses on commodity derivatives, that are not embedded derivatives, are recorded immediately to earnings as commodity derivative (gain) loss, net. The components of commodity derivative (gain) loss, net were as follows (in thousands):

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	Nine Months Ended September 30,	
	2012	2011
Change in unrealized (gains) losses on derivative contracts	$(89,478)	$(143,721)
Realized cash settlement losses	25,278	25,650
Total	$(64,200)	$(118,071)

With respect to our open derivative contracts at September 30, 2012 and 2011, the futures curve of forecasted commodity prices ("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 each respective period. The change in unrealized (gains) losses on derivative contracts in the first nine months of 2012 resulted in an $89.5 million gain in such net liability position due to the downward shift in the forward price curve for NYMEX crude oil from January 1 to September 30, 2012. The change in unrealized (gains) losses on derivative contracts in the first nine months of 2011 resulted in a $143.7 million gain due to a more significant downward shift in the same forward price curve from January 1 to September 30, 2011.

Income Tax Expense. Income tax expense totaled $199.5 million for the first nine months of 2012 as compared to $253.3 million of income tax for the first nine months of 2011, a decrease of $53.8 million that was mainly related to $150.2 million in lower pre-tax income between periods.

Our effective tax rates for the periods ended September 30, 2012 and 2011 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 only increased slightly between periods from 37.1% for the first nine months of 2011 to 37.5% for the first nine months of 2012.

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Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

	Three Months Ended September 30,	
	2012	2011
Net production:		
Oil (MMBbl)	5.9	4.8
NGLs (MMBOE)	0.7	0.6
Natural gas (Bcf)	6.3	6.8
Total production (MMBOE)	7.6	6.5
Net sales (in millions):		
Oil (1)	$478.6	$402.5
NGLs	21.1	32.1
Natural gas (1)	21.5	34.0
Total oil and natural gas sales	$521.2	$468.6
Average sales prices:		
Oil (per Bbl)	$81.66	$83.79
Effect of oil hedges on average price (per Bbl)	(0.80)	(0.39)
Oil net of hedging (per Bbl)	$80.86	$83.40
Average NYMEX price (per Bbl)	$92.19	$89.81
NGLs (per BOE)	$30.77	$56.88
Natural gas (per Mcf)	$3.39	$5.00
Effect of natural gas hedges on average price (per Mcf)	0.05	0.02
Natural gas net of hedging (per Mcf)	$3.44	$5.02
Average NYMEX price (per Mcf)	$2.81	$4.20
Cost and expenses (per BOE):		
Lease operating expenses	$12.35	$11.94
Production taxes	$5.73	$5.31
Depreciation, depletion and amortization expense	$23.63	$18.90
General and administrative expenses	$3.29	$3.56

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $52.6 million to $521.2 million in the third quarter of 2012 compared to the same period in 2011. Sales revenue is a function of oil and gas volumes sold and average commodity prices realized. Our oil and NGL sales volumes each increased 22% between periods, while our natural gas sales volumes decreased 7%. The oil volume increase resulted primarily from drilling success at our Lewis & Clark/Pronghorn prospects, Sanish field and our Hidden Bench prospect. During the third quarter of 2012, oil production from our Lewis & Clark/Pronghorn prospects increased 555 MBbl compared to the third quarter of 2011, while oil production from our Sanish field increased 535 MBbl, and oil production from our Hidden Bench prospect increased 105 MBbl over the same period in 2011. These production increases were partially offset by the Trust II divestiture, which decreased oil production by 295 MBOE in the third quarter of 2012. 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. 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, Sanish field and our Hidden Bench prospect. The gas volume decline between periods was primarily the result of the Trust II divestiture, which decreased third quarter 2012 gas production by 600 MMcf, as well as normal production decline across several areas. During the third quarter of 2012, gas production at our Flat Rock field decreased 530 MMcf, and gas production at our Canyon field decreased 150 MMcf compared to the third quarter of 2011. These gas volume decreases were partially offset by higher associated gas production at our Lewis & Clark/Pronghorn prospects and our Sanish field, related to new wells drilled and completed in these areas during the past twelve months.

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Partially offsetting the above production-related increases in net revenue, were decreases in the average sales prices realized for oil, NGLs and natural gas from the third quarter of 2011 to the third quarter of 2012. Our average price for oil before the effects of hedging decreased 3% between periods, while our average price for NGLs decreased 46%, and our average price for natural gas before the effects of hedging decreased 32%.

Gain (Loss) on Hedging Activities. Our gain on hedging activities decreased $1.5 million in 2012 as compared to the third quarter of 2011, and it consisted of the following (in thousands):

	Three Months Ended September 30,	
	2012	2011
Gains reclassified from AOCI on de-designated hedges	$398	$1,871

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 as gain on hedging activities.

See Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding oil and natural gas derivatives as of October 1, 2012.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during the third quarter of 2012 were $93.9 million, a $16.2 million increase over the same period in 2011. This rise in LOE in 2012 was primarily related to a $19.4 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. Partially offsetting this increase was a lower level of well workover activity which decreased from $22.1 million for the third quarter of 2011 to $18.9 million for the third quarter of 2012.

Our lease operating expenses on a BOE basis also increased during the third quarter of 2012. LOE per BOE amounted to $12.35 for the third quarter of 2012, which was up from $11.94 per BOE for the third quarter of 2011. This increase was mainly due to the higher costs of oil field goods and services and plant expenses in 2012, as discussed above, which were largely offset by higher overall production volumes between periods.

Production Taxes. Our production taxes during the third quarter of 2012 were $43.5 million, a $9.0 million increase over the same period in 2011, which increase was primarily due to higher oil and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.4% and 7.4% for the third quarter of 2012 and 2011, respectively. Our production tax rate for the third quarter of 2012 was greater than the rate for the same period in 2011 due to successful wells completed during the past twelve months in North Dakota, which has an 11.5% production tax rate. In addition, we take advantage of credits and exemptions allowed in our various taxing jurisdictions.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense increased $56.7 million in 2012 as compared to the third quarter of 2011. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30,

	2012	2011
Depletion	$176,917	$120,178
Depreciation	966	706
Accretion of asset retirement obligations	1,704	2,006
Total	$179,587	$122,890

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DD&A increased in the third quarter of 2012 primarily due to $56.7 million in higher depletion expense between periods. This increase was the result of $31.1 million in higher depletion due to an increase in our depletion rate between periods and $25.6 million in higher depletion due to a rise in overall production volumes during the third quarter of 2012. On a BOE basis, our DD&A rate of $23.63 for the third quarter of 2012 was 25% higher than the rate of $18.90 for the same period in 2011. The higher DD&A rate was mainly due to $1,917.7 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 $5.0 million in the third quarter of 2012 as compared to the third quarter of 2011. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended September 30,	
	2012	2011
Exploration	$10,338	$9,440
Impairment	13,544	9,478
Total	$23,882	$18,918

Exploration costs increased $0.9 million during the third quarter of 2012 as compared to the same period in 2011 primarily due to higher exploratory dry hole costs. During the third quarter of 2012, we drilled one exploratory dry hole in the Rocky Mountains region totaling $1.9 million, while we drilled no exploratory dry holes in the third quarter of 2011. This increase in dry hole costs was partially offset by a decrease in geological and geophysical ("G&G") activity. G&G costs, such as seismic studies, amounted to $2.1 million during the third quarter of 2012 as compared to $3.3 million during the same period in 2011.

Impairment expense in the third quarter of 2012 and 2011 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $13.4 million for the third quarter of 2012 as compared to $9.4 million for the third quarter of 2011.

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

	Three Months Ended September 30,	
	2012	2011
General and administrative expenses	$49,111	$41,010
Reimbursements and allocations	(24,077)	(17,866)
General and administrative expense, net	$25,034	$23,144

General and administrative expense before reimbursements and allocations increased $8.1 million during the third quarter of 2012 as compared to the same period in 2011 primarily due to higher employee compensation and a $1.9 million increase in professional fees and information technology costs. Employee compensation increased $5.9 million in the third quarter of 2012 as compared to the second quarter of 2012 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods.

The increase in reimbursements and allocations for the third quarter of 2012 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales remained constant at 5% for the third quarters of 2011 and 2012.

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

	Three Months Ended September 30,	
	2012	2011
Senior Subordinated Notes	$10,063	$10,063
Credit agreement	7,040	4,631
Amortization of debt issue costs and debt discount	2,360	2,115
Other	46	46
Capitalized interest	(775)	(725)
Total	$18,734	$16,130

The increase in interest expense of $2.6 million between periods was mainly attributable to a $2.4 million increase in the amount of interest incurred on our credit agreement during the third quarter of 2012 as compared to the third quarter of 2011. Our credit agreement interest was higher in 2012 due to a greater amount of borrowings outstanding under this facility. Our weighted average debt outstanding during the third quarter of 2012 was $1,522.7 million versus $1,220.1 million for the third quarter of 2011. Our weighted average effective cash interest rate was 4.5% during the third quarter of 2012 compared to 4.8% during the third quarter of 2011.

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 is only impacted to the extent that settlements under these contracts result in making or receiving a payment from the counterparty, and only realized cash settlement gains and losses on commodity derivatives, that are not embedded derivatives, are 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 September 30,	
	2012	2011
Change in unrealized (gains) losses on derivative contracts	$2,006	$(140,606)
Realized cash settlement losses	4,415	1,714
Total	$6,421	$(138,892)

With respect to our open derivative contracts at September 30, 2012 and 2011, the futures curve of forecasted commodity prices (“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 each respective period. The change in unrealized (gains) losses on derivative contracts in the third quarter of 2012 resulted in a $2.0 million loss in such net liability position due to the upward shift in the forward price curve for NYMEX crude oil from July 1 to September 30, 2012. The change in unrealized (gains) losses on derivative contracts in 2011 resulted in a $140.6 million gain due to a significant downward shift in the same forward price curve from July 1 to September 30, 2011.

Income Tax Expense. Income tax expense totaled $50.1 million for the third quarter of 2012 as compared to $126.1 million of income tax for the third quarter of 2011, a decrease of $76.0 million that was mainly related to $199.1 million in lower pre-tax income between periods.

Our effective tax rates for the periods ended September 30, 2012 and 2011 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our effective tax rate only decreased slightly between periods from 38.0% for the third quarter of 2011 to 37.6% for the third quarter of 2012.

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Liquidity and Capital Resources

Overview. At September 30, 2012, our debt to total capitalization ratio was 32.3%, we had $26.1 million of cash on hand and $3,358.9 million of equity. At December 31, 2011, our debt to total capitalization ratio was 31.4%, we had $15.8 million of cash on hand and $3,020.9 million of equity. During the first nine months of 2012, we generated $1,017.9 million of cash provided by operating activities, an increase of $154.2 million over the same period in 2011. Cash provided by operating activities increased primarily due to higher crude oil and NGL production volumes in the first nine months of 2012. This positive factor was partially offset by lower realized sales prices for oil, NGLs and natural gas and lower natural gas production volumes in the first nine months of 2012, as well as increased lease operating expenses, production taxes, general and administrative and cash interest expense during the first nine months of 2012 as compared to the same period in 2011. Cash flows from operating activities plus $322.2 million of proceeds from the sale of Trust II units, $69.2 million in proceeds from the sale of oil and gas properties and $220.0 million in net borrowings under our credit agreement were used to finance $1,509.6 million of drilling and development expenditures and $103.0 million of cash acquisition capital expenditures paid in the first nine months of 2012. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region during the first nine months of 2012 (in thousands):

	Drilling and Development Expenditures(1)	Undeveloped Leasehold Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 1,047,133 (2)	$ 71,749	$ 16,694	$ 1,135,576	74%
Permian Basin	293,390	3,828	12,143	309,361	20%
Mid-Continent	59,748	-	1,391	61,139	4%
Gulf Coast	8,063	17,716	2,905	28,684	2%
Michigan	2,208	4	459	2,671	-
Total incurred	1,410,542	93,297	33,592	1,537,431	100%
Decrease in accrued capital expenditures	30,690	-	-	30,690	
Total paid	$ 1,441,232	$ 93,297	$ 33,592	$ 1,568,121	

(1) For purposes of this schedule, exploratory dry hole costs of $2.1 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.

(2) Proceeds from the sale of the Belfield gas plant of $66.2 million have been included above as a reduction to drilling and development expenditures in the Rocky Mountains region.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2012 capital budget is $1,900.0 million, which we expect to fund substantially with net cash provided by our operating activities, oil and gas property divestitures and borrowings under our credit facility. This represents a 3% increase from the $1,840.2 million incurred on exploration, development and acreage expenditures during 2011. We have increased our 2012 capital budget from our actual level of 2011 expenditures in response to higher crude oil production volumes projected for 2012 and our development of projects expected to generate attractive rates of return. We expect to allocate $1,522.0 million of our 2012 budget to exploration and development activity, $163.0 million for undeveloped acreage and $215.0 million for facilities. Although we have only budgeted $163.0 million for undeveloped leaseholds in 2012, 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 $1,900.0 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.

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Credit Agreement. Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), our wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of September 30, 2012 had a borrowing base of $1.5 billion with $497.6 million of available borrowing capacity, which was net of $1.0 billion in borrowings and $2.4 million in letters of credit outstanding. In October 2012, Whiting Oil and Gas entered into an amendment to its credit agreement that increased the borrowing base under the facility from $1.5 billion to $2.5 billion, of which $2.0 billion has been committed by lenders and is available for borrowing. We may increase the maximum aggregate amount of commitments under the credit agreement from $2.0 billion to $2.5 billion if certain conditions are satisfied, including the consent of lenders participating in the increase.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of September 30, 2012, $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, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, 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 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for the quarters ending March 31, 2013 and thereafter and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. We were in compliance with our covenants under the credit agreement as of September 30, 2012.

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.

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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.

The indentures governing the notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. Additionally, the indentures governing the notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of September 30, 2012. 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 $127.8 million (which amount comprises both the long and short-term portions of this obligation) as of September 30, 2012, since we cannot determine with accuracy the timing or amounts of future payments other than the short-term portion. The following table summarizes our obligations and commitments as of September 30, 2012 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 (a)	$ 1,600,000	$ -	$ 250,000	$ 1,000,000	$ 350,000
Cash interest expense on debt (b)	238,443	62,450	95,733	57,510	22,750
Derivative contract liability fair value (c)	41,430	33,499	7,931	-	-
Asset retirement obligations (d)	68,366	11,183	4,717	4,822	47,644
Tax sharing liability (e)	24,372	1,526	22,846	-	-
Purchase obligations (f)	725,266	58,001	186,907	195,810	284,548
Drilling rig contracts (g)	209,369	95,238	110,000	4,131	-
Operating leases (h)	15,347	5,792	4,592	2,302	2,661
Total	$ 2,922,593	$ 267,689	$ 682,726	$ 1,264,575	$ 707,603

(a) 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 dates of these instruments.

(b)

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 these 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%.

(c) The above derivative obligation at September 30, 2012 primarily consists of (i) a $37.0 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; (ii) a $1.1 million payable to Whiting USA Trust I ("Trust I") for derivative contracts that we have entered into but have in turn conveyed to Trust I (although these derivatives are in a fair value asset position at quarter end, 75.8% of such derivative assets are due to Trust I under the terms of the conveyance); and (iii) a $3.3 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 also 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 our open derivative contracts at September 30, 2012 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.

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(d) 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.

(e) 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 future 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 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.

(f) 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 recovery projects at 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 June 2013 and one expiring in December 2017, 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 enhanced recovery 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.

(g) We have 12 drilling rigs under long-term contract, of which one drilling rig expires in 2012, two in 2013, six in 2014 and three in 2015. All of these rigs are operating in the Rocky Mountains region. As of September 30, 2012, early termination of the remaining contracts would require termination penalties of $161.1 million, which would be in lieu of paying the remaining drilling commitments of $209.4 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.

(h) We lease 135,026 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, 46,300 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, 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, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to the Adopted and Recently Issued Accounting Pronouncements footnote in the

Notes to Consolidated Financial Statements.

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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, 2011.

Effects of Inflation and Pricing

We experienced increased costs during 2011 and the first nine months of 2012 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.

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 enhanced oil recovery 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; impacts of the global recession and tight credit markets; 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; 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, 2011. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Quarterly Report on Form 10-Q.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

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, 2011 and have not materially changed since that report was filed.

Commodity Derivative Contracts—Our outstanding hedges as of October 1, 2012 are summarized below:

Whiting Petroleum Corporation

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Collars	Crude Oil	10/2012 to 12/2012	1,150,000	$68.85/$106.48
	Crude Oil	01/2013 to 03/2013	290,000	$47.67/$90.21
	Crude Oil	04/2013 to 06/2013	290,000	$47.67/$90.21
	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	01/2013 to 03/2013	910,000	$70.00/$85.00/$114.80
	Crude Oil	04/2013 to 06/2013	910,000	$70.00/$85.00/$114.80
	Crude Oil	07/2013 to 09/2013	910,000	$70.00/$85.00/$114.80
	Crude Oil	10/2013 to 12/2013	910,000	$70.00/$85.00/$114.80

(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.

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I ("Trust I"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 105 MBbl of crude oil and 380 MMcf of natural gas in 2012, have been conveyed to Trust I, and therefore such payments will be included in Trust I's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. Our retention of 10% of these net proceeds combined with our ownership of 2,186,389 Trust I units, results in third-party public holders of Trust I units receiving 75.8%, while we retain 24.2%, of future economic results of such hedges. No additional hedges are allowed to be placed on Trust I assets.

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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 I (of which we retain 24.2% of the future economic results and third-party public holders of Trust I units receive 75.8% of the future economic results):

Conveyed to Whiting USA Trust I

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)/(Mcf)	Weighted Average NYMEX Floor/Ceiling
Collars	Crude Oil	10/2012 to 12/2012	35,028	$74.00/$142.21
	Natural Gas	10/2012 to 12/2012	126,613	$7.00/$13.40

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 1,170 MBbl of crude oil from 2012 through 2014, have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. This results in third-party public holders of Trust II units receiving 90%, while we retain 10%, of the future economic results of such hedges. No additional hedges are allowed to be placed on Trust II assets.

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

Conveyed to Whiting USA Trust II

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	NYMEX Floor/Ceiling
Collars	Crude Oil	10/2012 to 12/2012	46,800	$80.00/$122.50
	Crude Oil	01/2013 to 03/2013	45,600	$80.00/$122.50
	Crude Oil	04/2013 to 06/2013	45,500	$80.00/$122.50
	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 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 hedges outstanding as of September 30, 2012, a hypothetical upward or downward shift of $10.00 per Bbl in the NYMEX forward curve as of September 30, 2012 would cause a decrease or increase, respectively, of $82.0 million in our commodity derivative (gain) loss. For the natural gas hedges outstanding as of September 30, 2012, a hypothetical $1.00 per Mcf upward or downward shift in the NYMEX forward curve as of September 30, 2012 would cause a decrease or increase, respectively, in our commodity derivative (gain) loss of $0.1 million.

We have various fixed price gas sales contracts with end users for a portion of the natural gas we produce in Colorado, Michigan and Utah. Our estimated future production volumes to be sold under these fixed price contracts as of October 1, 2012 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	10/2012 to 12/2012	398,667	$5.46
Natural Gas	01/2013 to 03/2013	360,000	$5.47
Natural Gas	04/2013 to 06/2013	364,000	$5.47
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

Embedded Commodity Derivative Contracts—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. We have entered into certain contracts for oil field goods and services with price adjustment clauses that are linked to changes in NYMEX crude oil prices, in order to reduce our exposure to paying higher than the market rates for these goods and services in a climate of declining oil prices. We have determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host contracts, and we have therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in the consolidated financial statements. These embedded commodity derivative contracts have not been designated as hedges, and therefore all changes in fair value since inception have been recorded immediately to earnings.

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As of September 30, 2012, we had two contracts with drilling rig companies, whereby the rig day rates increased or decreased along with changes in the price of NYMEX crude oil. These drilling rig contracts have termination dates of April 2014 and September 2014. For these embedded commodity derivative contracts, a hypothetical upward or downward shift of $10.00 per Bbl in the NYMEX forward curve as of September 30, 2012 would cause a decrease or increase, respectively, of $0.9 million in our commodity derivative (gain) loss.

In May 2011, we entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in our enhanced oil recovery project at our North Ward Estes field in Texas. The price per Mcf of CO2 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 $10.00 per Bbl in the NYMEX forward curve as of September 30, 2012 would cause a decrease or increase, respectively, of $16.0 million in our commodity derivative (gain) loss.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our management evaluated, with the participation of our Chairman and Chief Executive Officer and our Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of September 30, 2012. Based upon their evaluation of these disclosures controls and procedures, the Chairman and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of September 30, 2012 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended September 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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, 2011. No material change to such risk factors has occurred during the nine months ended September 30, 2012.

Item 6. Exhibits

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on this 25th day of October, 2012.

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

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(4.1)	Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of October 19, 2012, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 19, 2012 (File No. 001-31899)].
(31.1)	Certification by the Chairman and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
(101)	The following materials from Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of September 30, 2012 and December 31, 2011, (ii) the Consolidated Statements of Income for the Three and Nine Months Ended September 30, 2012 and 2011, (iii) the Consolidated Statements of Comprehensive Income for the Three and Nine Months Ended September 30, 2012 and 2011, (iv) the Consolidated Statements of Cash Flows for the Nine Months Ended September 30, 2012 and 2011, (v) the Consolidated Statements of Equity for the Nine Months Ended September 30, 2012 and 2011 and (vi) Notes to Consolidated Financial Statements.