WHITING PETROLEUM CORP
Form 10-Q
October 29, 2010

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, 2010

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 filer	T	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, 2010: 58,548,894 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.

“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/d” - One thousand BOE per day.

“Mcf” - One thousand cubic feet of natural gas.

“MMBbl” - One million barrels of oil or other liquid hydrocarbons.

“MMBOE” - One million BOE.

“MMBtu” - One million British Thermal Units.

“MMcf” - One million cubic feet of natural gas.

“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.

“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; to share in production, subject to all royalties, overriding royalties and other burdens; and to share in all costs of exploration, development, 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, 2010		December 31, 2009
ASSETS				
Current assets:				
Cash and cash equivalents	$	3,211	$	11,960
Accounts receivable trade, net		182,355		152,082
Prepaid expenses and other		14,535		11,983
Total current assets		200,101		176,025
Property and equipment:				
Oil and gas properties, successful efforts method:				
Proved properties		5,392,276		4,870,688
Unproved properties		177,638		100,706
Other property and equipment		89,695		100,833
Total property and equipment		5,659,609		5,072,227
Less accumulated depreciation, depletion and amortization		(1,546,476)		(1,274,121)
Total property and equipment, net		4,113,133		3,798,106
Debt issuance costs		22,935		24,672
Other long-term assets		30,361		30,739
TOTAL ASSETS	$	4,366,530	$	4,029,542
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable trade	$	55,121	$	14,023
Accrued capital expenditures		73,682		29,998
Accrued liabilities and other		113,452		110,320
Revenues and royalties payable		75,548		46,327
Taxes payable		28,403		21,188
Derivative liabilities		33,432		49,551
Deferred income taxes		4,500		11,325
Total current liabilities		384,138		282,732
Long-term debt		700,000		779,585
Deferred income taxes		500,095		341,037
Derivative liabilities		91,250		137,621
Production Participation Plan liability		78,983		69,433
Asset retirement obligations		73,922		66,846
Deferred gain on sale		47,477		58,462
Other long-term liabilities		25,314		23,741
Total liabilities		1,901,179		1,759,457
Commitments and contingencies				
Stockholders' equity:				

Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 172,500 shares issued and outstanding as of September 30, 2010 and 3,450,000 shares issued and outstanding as of December 31, 2009, aggregate liquidation preference of $17,250,000		-		3
Common stock, $0.001 par value, 175,000,000 shares authorized; 58,986,415 issued and 58,548,894 outstanding as of September 30, 2010, 51,363,638 issued and 50,845,374 outstanding as of December 31, 2009		59		51
Additional paid-in capital		1,547,536		1,546,635
Accumulated other comprehensive income		8,014		20,413
Retained earnings		909,742		702,983
Total stockholders’ equity		2,465,351		2,270,085
TOTAL LIABILITIES AND STOCKHOLDERS’ EQUITY	$	4,366,530	$	4,029,542

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, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 365,239	$ 256,074	$ 1,068,961	$ 616,552
Gain on hedging activities	4,383	7,774	19,641	28,072
Amortization of deferred gain on sale	3,854	4,222	11,613	12,595
Gain on sale of properties	-	1,101	1,918	5,709
Interest income and other	258	156	498	396
Total revenues and other income	373,734	269,327	1,102,631	663,324
COSTS AND EXPENSES:				
Lease operating	69,001	58,807	197,586	177,343
Production taxes	26,193	18,792	77,341	43,225
Depreciation, depletion and amortization	97,704	101,273	289,836	301,622
Exploration and impairment	10,500	12,422	37,915	39,528
General and administrative	19,480	11,314	48,516	30,576
Interest expense	14,579	15,647	45,903	49,020
Loss on early extinguishment of debt	6,235	-	6,235	-
Change in Production Participation Plan liability	3,858	(678)	9,550	3,002
Commodity derivative (gain) loss, net	31,765	(10,391)	(46,654)	171,906
Total costs and expenses	279,315	207,186	666,228	816,222
INCOME (LOSS) BEFORE INCOME TAXES	94,419	62,141	436,403	(152,898)
INCOME TAX EXPENSE (BENEFIT):				
Current	(170)	(507)	6,468	(1,046)
Deferred	36,057	26,793	159,475	(50,785)
Total income tax expense (benefit)	35,887	26,286	165,943	(51,831)
NET INCOME (LOSS)	58,532	35,855	270,460	(101,067)
Preferred stock dividends	(52,920)	(4,911)	(63,701)	(4,911)
NET INCOME (LOSS) AVAILABLE TO COMMON	$ 5,612	$ 30,944	$ 206,759	$ (105,978)

SHAREHOLDERS									
EARNINGS (LOSS) PER COMMON SHARE:									
Basic	$	0.12	$	0.59	$	4.04	$	(2.15	)
Diluted	$	0.12	$	0.59	$	4.00	$	(2.15	)
WEIGHTED AVERAGE SHARES OUTSTANDING:									
Basic		52,148		50,845		51,356		49,774	
Diluted		52,453		51,174		52,096		49,774	

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, 2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 270,460	$ (101,067)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	289,836	301,622
Deferred income tax expense (benefit)	159,475	(50,785)
Amortization of debt issuance costs and debt discount	8,525	8,143
Stock-based compensation	6,585	4,047
Amortization of deferred gain on sale	(11,613)	(12,595)
Gain on sale of properties	(1,918)	(5,709)
Undeveloped leasehold and oil and gas property impairments	12,054	14,743
Exploratory dry hole costs	2,796	2,344
Loss on early extinguishment of debt	6,235	-
Change in Production Participation Plan liability	9,550	3,002
Unrealized (gain) loss on derivative contracts	(82,213)	145,650
Other non-current	(4,495)	646
Changes in current assets and liabilities:		
Accounts receivable trade	(30,273)	(2,317)
Prepaid expenses and other	(637)	30,062
Accounts payable trade and accrued liabilities	49,464	(49,380)
Revenues and royalties payable	29,221	884
Taxes payable	7,215	1,530
Net cash provided by operating activities	720,267	290,820
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(102,256)	(31,475)
Drilling and development capital expenditures	(473,697)	(403,571)
Proceeds from sale of oil and gas properties	7,875	80,308
Net cash used in investing activities	(568,078)	(354,738)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of 6.5% Senior Subordinated Notes due 2018	350,000	-
Redemption of 7.25% Senior Subordinated Notes due 2012	(150,000)	-
Redemption of 7.25% Senior Subordinated Notes due 2013	(223,988)	-
Issuance of 6.25% convertible perpetual preferred stock	-	334,112
Issuance of common stock	-	234,753
Premium on induced conversion of 6.25% convertible perpetual preferred stock	(47,529)	-
Preferred stock dividends paid	(16,172)	(4,911)
Long-term borrowings under credit agreement	850,000	310,000
Repayments of long-term borrowings under credit agreement	(910,000)	(780,000)
Debt issuance costs	(7,570)	(23,141)
Restricted stock used for tax withholdings	(5,679)	(659)

Net cash (used in) provided by financing activities		(160,938)		70,154
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		(8,749)		6,236
CASH AND CASH EQUIVALENTS:				
Beginning of period		11,960		9,624
End of period	$	3,211	$	15,860
NONCASH INVESTING ACTIVITIES:				
Accrued capital expenditures during the period	$	73,682	$	23,372
NONCASH FINANCING ACTIVITIES:				
Issuance of common stock related to the induced conversion of preferred stock	$	317,406	$	-
Preferred stock cancelled in connection with its induced conversion	$	(317,406)	$	-

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
AND COMPREHENSIVE INCOME (Unaudited)
(In thousands)

	Preferred Stock Shares	Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity	Comprehensive Income (Loss)
BALANCES-January 1, 2009	-	$-	42,582	$43	$971,310	$17,271	$820,167	$1,808,791	
Net loss	-	-	-	-	-	-	(101,067)	(101,067)	$(101,067)
Change in derivative fair values, net of taxes of $7,799	-	-	-	-	-	13,348	-	13,348	13,348
Realized gain on settled derivative contracts, net of taxes of $4,933	-	-	-	-	-	(8,517)	-	(8,517)	(8,517)
Ineffectiveness loss on hedging activities, net of taxes of $8,355	-	-	-	-	-	14,300	-	14,300	14,300
OCI amortization on de-designated hedges, net of taxes of $5,390	-	-	-	-	-	(9,232)	-	(9,232)	(9,232)
Total comprehensive income									$(91,168)
Issuance of 6.25% convertible perpetual preferred stock	3,450	3	-	-	334,109	-	-	334,112	
Issuance of stock, secondary offering	-	-	8,450	8	234,745	-	-	234,753	
Restricted stock issued			364	-	-	-	-	-	
Restricted stock forfeited	-	-	(5)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(27)	-	(659)	-	-	(659)	
Tax effect from restricted stock vesting	-	-	-	-	(515)	-	-	(515)	
Stock-based compensation	-	-	-	-	4,047	-	-	4,047	
Preferred dividends paid	-	-	-	-	-	-	(4,911)	(4,911)	
BALANCES-September 30, 2009	3,450	$3	51,364	$51	$1,543,037	$27,170	$714,189	$2,284,450	
BALANCES-January 1, 2010	3,450	$3	51,364	$51	$1,546,635	$20,413	$702,983	$2,270,085	
Net income	-	-	-	-	-	-	270,460	270,460	$270,460

OCI amortization on de-designated hedges, net of taxes of $7,242	-	-	-	-	-	(12,399)	-	(12,399)	(12,399)
Total comprehensive income									$258,061
Induced conversion of convertible perpetual preferred stock	(3,277)	(3)	7,549	8	(5)	-	(47,529)	(47,529)	
Restricted stock issued	-	-	162	-	-	-	-	-	
Restricted stock forfeited	-	-	(11)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(78)	-	(5,679)	-	-	(5,679)	
Stock-based compensation	-	-	-	-	6,585	-	-	6,585	
Preferred dividends paid	-	-	-	-	-	-	(16,172)	(16,172)	
BALANCES-September 30, 2010	173	$-	58,986	$59	$1,547,536	$8,014	$909,742	$2,465,351	

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 acquires, exploits, develops and explores for crude oil, natural gas and natural gas liquids primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan 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, all of which are wholly-owned, and Whiting’s pro rata share of the accounts of Whiting USA Trust I pursuant to Whiting’s 15.8% ownership interest. 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 2009 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 2009 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.

Reclassifications—In accordance with Regulation S-X Article 10, the Company has condensed certain line items within the current period financial statements, and certain prior period balances were reclassified to conform to the current year presentation accordingly. Such reclassifications had no impact on net income, cash flows or stockholders’ equity previously reported.

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2. ACQUISITIONS AND DIVESTITURES

2010 Activity

In September 2010, Whiting acquired operated interests in 19 producing oil and gas wells, undeveloped acreage, and gathering lines, all of which are located on approximately 20,400 gross (16,100 net) acres in Weld County, Colorado. The aggregate unadjusted purchase price was $19.2 million, and substantially all of it was allocated to the properties and acreage acquired.

In August 2010, Whiting acquired oil and gas leasehold interests covering approximately 112,000 gross (90,200 net) acres in the Montana portion of the Williston Basin for $26.0 million. The undeveloped acreage is located in Roosevelt and Sheridan counties.

There were no significant divestitures during the first nine months of 2010.

2009 Acquisitions

During 2009, Whiting acquired additional royalty and overriding royalty interests in the North Ward Estes field and various other fields in the Permian Basin in two separate transactions with private owners. Also included in these transactions were contractual rights, including an option to participate for an aggregate 10% working interest and right to back in after payout for an additional aggregate 15% working interest in the development of deeper pay zones on acreage under and adjoining the North Ward Estes field.

Whiting completed the first acquisition of additional royalty and overriding royalty interests in November 2009, with a purchase price of $38.7 million and an effective date of October 1, 2009. The Company completed the second acquisition of additional royalty and overriding royalty interests in December 2009, with a purchase price of $27.4 million and an effective date of November 1, 2009. Reserves attributable to royalty and overriding royalty interests are not burdened by operating expenses or any additional capital costs, including CO2 costs, which are paid by the working interest owners. These two acquisitions were funded primarily from net cash provided by operating activities. Substantially all of the purchase price was allocated to the properties acquired.

2009 Participation Agreement

In June 2009, Whiting entered into a participation agreement with a privately held independent oil company covering twenty-five 1,280-acre units and one 640-acre unit located primarily in the western portion of the Sanish field in Mountrail County, North Dakota. Under the terms of the agreement, the private company agreed to pay 65% of Whiting's net drilling and well completion costs to receive 50% of Whiting's working interest and net revenue interest in the first and second wells planned for each of the units. Pursuant to the agreement, Whiting will remain the operator for each unit.

At the closing of the agreement, the private company paid Whiting $107.3 million, representing $6.4 million for acreage costs, $65.8 million for 65% of Whiting's cost in 18 wells drilled or drilling and $35.1 million for a 50% interest in Whiting's Robinson Lake gas plant and oil and gas gathering system. Whiting used these proceeds 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, 2010 and December 31, 2009 (in thousands):

	September 30, 2010	December 31, 2009
Credit Agreement	$100,000	$160,000
6.5% Senior Subordinated Notes due 2018	350,000	-
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,147	-	218,853
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $268	-	150,732
Total debt	$700,000	$779,585

Credit Agreement—As of September 30, 2010, Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), the Company’s wholly-owned subsidiary, had a credit agreement with a syndicate of banks, and this credit facility had a borrowing base of $1.1 billion with $999.6 million of available borrowing capacity, which was net of $100.0 million in borrowings and $0.4 million in letters of credit outstanding. The credit agreement provided for interest only payments until April 2012, when the agreement expired and all outstanding borrowings were due. In October 2010, Whiting Oil and Gas entered into a Fifth Amended and Restated Credit Agreement with its bank syndicate, which replaced the existing credit agreement. This amended credit agreement extended the principal repayment date from April 2012 to October 2015. Further information on the terms of the new credit agreement is discussed in the note on Subsequent Events. The following is a description of the credit agreement in place as of September 30, 2010.

The borrowing base under the credit agreement was determined at the discretion of the lenders, based on the collateral value of the proved reserves that had been mortgaged to the lenders, and was 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 have reduced the amount of the borrowing base. Whiting Oil and Gas could have, throughout the term of the credit agreement, borrowed, repaid and reborrowed up to the borrowing base in effect at any given time. A portion of the revolving credit agreement in an aggregate amount not to exceed $50.0 million could have been 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, 2010, $49.6 million was available for additional letters of credit under the agreement.

Interest accrued 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. The Company also incurred commitment fees of 0.50% on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base, which were included as a component of interest expense. At September 30, 2010, the weighted average interest rate on the outstanding principal balance borrowed under the credit agreement was 2.3%.

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Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans
Less than 0.25 to 1.0	1.1250%	2.00%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.1375%	2.25%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.6250%	2.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.8750%	2.75%
Greater than or equal to 0.90 to 1.0	2.1250%	3.00%

The credit agreement contained restrictive covenants that may have limited 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. The credit agreement required 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 4.5 to 1.0 for quarters ending prior to and on September 30, 2010, 4.25 to 1.0 for quarters ending December 31, 2010 to June 30, 2011 and 4.0 to 1.0 for quarters ending September 30, 2011 and thereafter, (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, and (iii) to not exceed a senior secured debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 2.5 to 1.0. Except for limited exceptions, which included the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement restricted its ability to make any dividend payments or distributions on its common stock or principal payments on its senior notes. The Company was in compliance with its covenants under the credit agreement as of September 30, 2010.

The obligations of Whiting Oil and Gas under the credit agreement were secured by a first lien on substantially all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation had guaranteed the obligations of Whiting Oil and Gas under the credit agreement and 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 $263.8 million as of September 30, 2010, based on quoted market prices for these same debt securities.

Redemption of 7.25% Senior Subordinated Notes Due 2012 and 2013—In September 2010, the Company paid $383.5 million to redeem all of its $150.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2012 and all of its $220.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2013, which consisted of a redemption price of 100.00% for the 2012 notes and 101.8125% for the 2013 notes and included the payment of accrued and unpaid interest on such notes. The Company financed the redemption of the 2012 and 2013 notes with borrowings under its credit agreement. As a result of the redemption, Whiting recognized a $6.2 million loss on early extinguishment of debt, which consisted of a cash charge of $4.0 million related to the redemption premium on the 2013 notes and a non-cash charge of $2.2 million related to the acceleration of debt discounts and unamortized debt issuance costs.

Issuance of 6.5% Senior Subordinated Notes Due 2018—In September 2010, the Company issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. The Company used the net proceeds from this issuance to repay a portion of the debt, which was borrowed to redeem its 2012 and 2013 notes, outstanding under its credit agreement. The estimated fair value of these notes was $357.4 million as of September 30, 2010, based on quoted market prices for these same debt securities.

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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, 2010 and December 31, 2009 were $5.7 million and $10.3 million, respectively, and are included in accrued liabilities and other. The following table provides a reconciliation of the Company's asset retirement obligations for the nine months ended September 30, 2010 (in thousands):

Asset retirement obligation, January 1, 2010	$77,186
Additional liability incurred	2,277
Revisions in estimated cash flows	1,331
Accretion expense	5,421
Obligations on sold properties	(2,942)
Liabilities settled	(3,611)
Asset retirement obligation, September 30, 2010	$79,662

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 also 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 Whiting USA Trust I (the "Trust") derivatives, entered into to hedge forecasted crude oil and natural gas production revenues, as of October 15, 2010.

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	Whiting Petroleum Corporation			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Oct – Dec 2010	2,415,437	118,336	$64.43 - $91.26	$7.00 - $14.20
Jan – Dec 2011	9,655,039	436,510	$60.40 - $96.90	$6.50 - $14.62
Jan – Dec 2012	4,065,091	384,002	$50.08 - $95.28	$6.50 - $14.27
Jan – Nov 2013	3,090,000	-	$47.64 - $89.90	n/a
Total	19,225,567	938,848		

Derivatives conveyed to Whiting USA Trust I. In connection with the Company's conveyance in April 2008 of a term net profits interest to the Trust and related sale of 11,677,500 Trust 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 the Trust, and therefore such payments will be included in the Trust'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 units, results in third-party public holders of Trust units receiving 75.8%, and Whiting retaining 24.2%, of the future economic results of commodity derivative contracts conveyed to the Trust. 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 assets.

The 24.2% portion of Trust 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	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Oct – Dec 2010	30,437	118,336	$76.00 - $135.11	$7.00 - $14.20
Jan – Dec 2011	115,039	436,510	$74.00 - $140.15	$6.50 - $14.62
Jan – Dec 2012	105,091	384,002	$74.00 - $141.72	$6.50 - $14.27
Total	250,567	938,848		

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

	Third-party Public Holders of Trust Units			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)

Oct – Dec 2010	95,335	370,655	$76.00 - $135.11	$7.00 - $14.20
Jan – Dec 2011	360,329	1,367,249	$74.00 - $140.15	$6.50 - $14.62
Jan – Dec 2012	329,171	1,202,785	$74.00 - $141.72	$6.50 - $14.27
Total	784,835	2,940,689		

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Discontinuance of cash flow hedge accounting—Prior to April 1, 2009, the Company designated a portion of its commodity derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to other comprehensive income, while the Company's remaining commodity derivative contracts were not designated as hedges, with gains and losses from changes in fair value recognized immediately in earnings. Effective April 1, 2009, however, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges as of March 31, 2009 and elected to discontinue hedge accounting prospectively. As a result, subsequent to March 31, 2009 the Company recognizes all gains and losses from prospective changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income.

At March 31, 2009, accumulated other comprehensive income consisted of $59.8 million ($36.5 million net of tax) of unrealized gains, representing the mark-to-market value of the Company's open commodity contracts designated as cash flow hedges as of that date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on April 1, 2009, such mark-to-market values at March 31, 2009 are frozen in accumulated other comprehensive income as of the de-designation date and reclassified into earnings as the original hedged transactions affect income. During the three and nine months ended September 30, 2010, $4.4 million ($2.8 million net of tax) and $19.6 million ($12.4 million net of tax), respectively, of derivative gains relating to de-designated commodity hedges were reclassified from accumulated other comprehensive income into earnings.

As of September 30, 2010, accumulated other comprehensive income amounted to $12.7 million ($8.0 million net of tax), which consisted entirely of unrealized deferred gains on commodity derivative contracts that had been previously designated as cash flow hedges. During the next twelve months, the Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of $6.9 million related to de-designated commodity hedges.

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 sales exclusion. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands).

		Fair Value	
Not Designated as ASC 815 Hedges	Balance Sheet Classification	September 30, 2010	December 31, 2009
Derivative assets:			
Commodity contracts	Prepaid expenses and other	$ 6,638	$ 4,723
Commodity contracts	Other long-term assets	6,639	8,473
Total derivative assets		$ 13,277	$ 13,196
Derivative liabilities:			
Commodity contracts	Current derivative liabilities	$ 33,432	$ 49,551
Commodity contracts	Non-current derivative liabilities	91,250	137,621
Total derivative liabilities		$ 124,682	$ 187,172

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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, 2010 and 2009 (in thousands).

ASC 815 Cash Flow Hedging Relationships	Location of Gain (Loss) Not Recognized in Income	Gain Recognized in OCI (Effective Portion)	
		Nine Months Ended September 30,	
		2010	2009
Commodity contracts	Other comprehensive income	$ -	$ 21,147
		Three Months Ended September 30,	
		2010	2009
Commodity contracts	Other comprehensive income	$ -	$ -

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain (Loss) Reclassified from OCI into Income (Effective Portion)	
		Nine Months Ended September 30,	
		2010	2009
Commodity contracts	Gain on hedging activities	$ 19,641	$ 28,072
		Three Months Ended September 30,	
		2010	2009
Commodity contracts	Gain on hedging activities	$ 4,383	$ 7,774

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Loss Recognized in Income (Ineffective Portion)	
		Nine Months Ended September 30,	
		2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$ -	$ 22,655
		Three Months Ended September 30,	
		2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$ -	$ -

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income	
		Nine Months Ended September 30,	
		2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$ (46,654)	$ 149,251
		Three Months Ended September 30,	
		2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$ 31,765	$ (10,391)

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. Whiting 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 large 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 MEASURMENTS

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 end of the reporting period in which the availability of observable inputs no longer justifies classification in the original level.

The following table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2010, and indicates 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, 2010
Financial Assets				
Commodity derivatives - current	$-	$6,638	$-	$6,638
Commodity derivatives - non-current	-	6,639	-	6,639
Total financial assets	$-	$13,277	$-	$13,277
Financial Liabilities				
Commodity derivatives - current	$-	$33,432	$-	$33,432
Commodity derivatives - non-current	-	91,250	-	91,250
Total financial liabilities	$-	$124,682	$-	$124,682

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

Commodity Derivative Instruments. Commodity derivative instruments consist primarily of costless collars for crude oil and natural gas. The Company's costless collars are valued using industry-standard models, which are based on a market approach. These models consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of 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.

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Non-Recurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its non-recurring, non-financial measurements including business combinations, proved oil and gas property impairments and asset retirement obligations. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The following table presents information about the Company's non-financial assets and liabilities measured at fair value on a non-recurring basis as of September 30, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Net Carrying Value as of September 30, 2010	Fair Value Measurements Using			Pre-tax (Gain) Loss Nine Months Ended September 30, 2010
		Level 1	Level 2	Level 3	
Asset retirement obligations	$2,298	$-	$-	$2,277	$-
Total non-recurring assets at fair value	$2,298	$-	$-	$2,277	$-

The following methods and assumptions were used to estimate the fair values of the non-financial assets and liabilities in the table above:

Asset Retirement Obligations. The Company estimates the fair value of asset retirement obligations at the point they are incurred by calculating the present value of estimated future plug and abandonment costs. Such present value calculations use internally developed cash flow models, which are based on an income approach, and include various assumptions such as estimated amounts and timing of abandonment cash flows, the Company's credit-adjusted risk-free rate and future inflation rates. Given the unobservable nature of most of these inputs, the initial measurement of asset retirement obligation liabilities is deemed to use Level 3 inputs.

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 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, 2010 and 2009 amounted to $21.2 million and $10.4 million, respectively, charged to general and administrative expense and $2.9 million and $1.5 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.

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The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At September 30, 2010, the Company used three-year average historical NYMEX prices of $79.48 for crude oil and $5.81 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, 2010, 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 $146.3 million. This amount includes $15.3 million attributable to proved undeveloped oil and gas properties and $24.1 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2011. 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 estimated long-term liability related to the Plan (in thousands):

Long-term Production Participation Plan liability, January 1, 2010	$69,433
Change in liability for accretion, vesting, change in estimates and new Plan year activity	33,601
Cash payments accrued as compensation expense and reflected as a current payable	(24,051)
Long-term Production Participation Plan liability, September 30, 2010	$78,983

8. STOCKHOLDERS' EQUITY

Common Stock—In May 2010, Whiting's stockholders approved an amendment to the Company's Amended and Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 75,000,000 shares to 175,000,000 shares.

Common Stock Offering. In February 2009, the Company completed a public offering of its common stock, selling 8,450,000 shares of common stock at a price of $29.00 per share and providing net proceeds of $234.8 million after underwriters' fees and offering expenses. The Company used the net proceeds to repay a portion of the debt outstanding under its credit agreement.

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 and providing net proceeds of $334.1 million after underwriters' fees and offering expenses. The Company used the net proceeds to repay a portion of the debt outstanding under its credit agreement.

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 an initial conversion price of $43.4163, 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.

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Induced Conversion of 6.25% Convertible Perpetual Preferred Stock. In August 2010, Whiting commenced an offer to exchange up to 3,277,500, or 95%, of its preferred stock for the following consideration per share of preferred stock: 2.3033 shares of its common stock and a cash premium of $14.50. The exchange offer expired in September 2010 and resulted in the Company accepting 3,277,500 shares of preferred stock in exchange for the issuance of 7,549,010 shares of common stock and a cash premium payment of $47.5 million. Following the exchange offer, the 3,277,500 shares of preferred stock accepted in the exchange were cancelled, and a total of 172,500 shares of preferred stock remained outstanding.

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 nine months ended September 30, 2010 and 2009 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.

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,	
	2010	2009
Basic Earnings Per Share		
Numerator:		
Net income	$58,532	$35,855
Preferred stock dividends (1)	(52,077)	(5,797)
Net income available to common shareholders, basic	$6,455	$30,058
Denominator:		
Weighted average shares outstanding, basic	52,148	50,845

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	Three Months Ended September 30, 2010	2009
Diluted Earnings Per Share		
Numerator:		
Net income available to common shareholders, basic	$6,455	$30,058
Preferred stock dividends	-	-
Adjusted net income available to common shareholders, diluted	$6,455	$30,058
Denominator:		
Weighted average shares outstanding, basic	52,148	50,845
Restricted stock and stock options	305	329
Convertible perpetual preferred stock	-	-
Weighted average shares outstanding, diluted	52,453	51,174
Earnings per common share, basic	$0.12	$0.59
Earnings per common share, diluted	$0.12	$0.59

(1) For the three months ended September 30, 2010, amount includes a decrease of $0.8 million in preferred stock dividends for preferred stock dividends accumulated. For the three months ended September 30, 2009, amount includes an increase of $0.9 million in preferred stock dividends for preferred stock dividends accumulated.

For the three months ended September 30, 2010, the diluted earnings per share calculation excludes the effect of 6,797,564 incremental common shares (which were issuable upon the conversion of perpetual preferred stock as of a July 1, 2010 assumed conversion date) because their effect was anti-dilutive. For the three months ended September 30, 2009, the diluted earnings per share calculation excludes the effect of 7,946,324 common shares, which were issuable upon the assumed conversion of perpetual preferred stock, because their effect was anti-dilutive.

	Nine Months Ended September 30, 2010	2009
Basic Earnings Per Share		
Numerator:		
Net income (loss)	$270,460	$(101,067)
Preferred stock dividends (1)	(62,859)	(5,797)
Net income (loss) available to common shareholders, basic	$207,601	$(106,864)
Denominator:		
Weighted average shares outstanding, basic	51,356	49,774

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	Nine Months Ended September 30, 2010	2009
Diluted Earnings Per Share		
Numerator:		
Net income (loss) available to common shareholders, basic	$207,601	$(106,864)
Preferred stock dividends	809	-
Adjusted net income (loss) available to common shareholders, diluted	$208,410	$(106,864)
Denominator:		
Weighted average shares outstanding, basic	51,356	49,774
Restricted stock and stock options	343	-
Convertible perpetual preferred stock	397	-
Weighted average shares outstanding, diluted	52,096	49,774
Earnings (loss) per common share, basic	$4.04	$(2.15)
Earnings (loss) per common share, diluted	$4.00	$(2.15)

(1) For the nine months ended September 30, 2010, amount includes a decrease of $0.8 million in preferred stock dividends for preferred stock dividends accumulated. For the nine months ended September 30, 2009, amount includes an increase of $0.9 million in preferred stock dividends for preferred stock dividends accumulated.

For the nine months ended September 30, 2010, the diluted earnings per share calculation excludes the effect of 7,161,881 incremental common shares (which were issuable upon the conversion of perpetual preferred stock as of a January 1, 2010 assumed conversion date) because their effect was anti-dilutive. For the nine months ended September 30, 2009, the Company had a net loss. Therefore, the diluted earnings per share calculation for that period excludes the effect of 292,675 shares of restricted stock and stock options, as well as 2,881,634 weighted average shares of convertible preferred stock outstanding because their effect was anti-dilutive.

11. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, Improving Disclosures about Fair Value Measurements (“ASU 2010-06”), which provides amendments to FASB ASC Topic 820, Fair Value Measurements and Disclosures. The objective of ASU 2010-06 is to provide more robust disclosures about (i) the different classes of assets and liabilities measured at fair value, (ii) the valuation techniques and inputs used, (iii) the activity in Level 3 fair value measurements, and (iv) significant transfers between Levels 1, 2 and 3. ASU 2010-06 became effective for fiscal years and interim periods beginning after December 15, 2009. The Company adopted ASU 2010-06 effective January 1, 2010, which did not have an impact on its consolidated financial statements, other than additional disclosures.

12. SUBSEQUENT EVENT

In October 2010, Whiting Oil and Gas entered into a Fifth Amended and Restated Credit Agreement with its bank syndicate, which replaced the existing credit facility. This amended credit agreement maintained the borrowing base of $1.1 billion and extended the principal repayment date to October 2015. 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.

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The amended credit agreement provides for interest only payments until October 2015, when the entire amount borrowed is due. 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.

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

Under the amended credit agreement, the Company also incurs commitment fees of 0.50% on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base.

The amended 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. 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 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. Except for limited exceptions, which include the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement restricts the Company's ability to make any dividend payments or distributions on its common stock.

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.

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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 Whiti Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in acquisition, development, exploitation, production and exploration activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan 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 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;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows;
- seeking property acquisitions that complement our core areas; and
- allocating a portion of our capital budget to leasing and exploring prospect areas.

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation 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.

Although oil prices fell significantly after reaching a high in the third quarter of 2008 with a daily average NYMEX of $118.13 per Bbl, they have experienced a rebound in the second half of 2009 and first nine months of 2010. For example, the daily average NYMEX oil price was $43.21, $59.62, $68.29 and $76.17 per Bbl for the first, second, third and fourth quarters of 2009, respectively, and $78.79, $77.99 and $76.21 per Bbl for the first, second and third quarters of 2010, respectively. Additionally, natural gas prices have fallen significantly since their third quarter 2008 daily average NYMEX of $10.27 per Mcf and remained low throughout 2009, but have slightly increased during the first nine months of 2010. For example, daily average NYMEX natural gas prices declined to $3.99 per Mcf for 2009, but rose to $4.59 per Mcf for the first nine months of 2010. 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 reserve bookings. 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 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 recognized on our commodity derivatives, which may in turn cause us to experience net losses.

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2010 Highlights and Future Considerations

Operational Highlights. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish field increased 113% from 10.5 MBOE/d in the third quarter of 2009 to 22.3 MBOE/d in the third quarter of 2010. Based on results of our microseismic studies and reservoir pressure monitoring in both the Bakken and Three Forks formations, it appears that additional infill drilling is necessary to maximize primary recovery in the Sanish field. As a result, we have increased by 156 the total number of gross operated wells that we expect to drill in the Sanish field to 469 gross wells from 313 gross wells. We have also elected to drill three Three Forks wells per 1,280-acre unit as compared to its previous plan of two Three Forks wells per unit. This decision adds 80 potential gross well locations in the Sanish field. Including non-operated wells, we estimate that 323 gross wells remain to be drilled in the Sanish field as of October 15, 2010, for a total of 534 gross wells.

From January 1 through October 15, 2010, we completed 57 operated wells in the Sanish field, bringing to 121 the total number of operated wells in the field. As of October 15, 2010, 17 operated wells were being completed or awaiting completion and nine operated wells were being drilled in the Sanish field. In 2010, we intend to drill or participate in the drilling of a total of 98 gross (52 net) wells in the Sanish field, of which 88 will target the Bakken formation and ten will target the Three Forks formation.

Net production in the Parshall field decreased 25% from 6.8 MBOE/d in the third quarter of 2009 to 5.1 MBOE/d in the third quarter of 2010. This production decrease was primarily due to normal field production decline and reduced drilling in the area as the operator of the Parshall field has drilled almost all of its Bakken locations and is currently pursuing a moderate pace of development of the Three Forks formation with a one-rig program.

We continue to have significant development and related infrastructure activity in the Postle and North Ward Estes fields acquired in 2005, which have resulted in reserve additions and production increases. Our expansion of the CO_2 floods at both fields continues to generate positive results.

Production continued to increase from the Postle field, which is located in Texas County, Oklahoma and produces from the Morrow sandstone. In the third quarter of 2010, the field produced at an average net rate of 9.3 MBOE/d, representing a 7% increase from the 8.7 MBOE/d rate in the third quarter of 2009. We manage our CO_2 flood at Postle on a pattern-by-pattern basis in order to optimize utilization of CO_2, production and ultimate recovery. A pattern typically consists of a producing well surrounded by four water/CO_2 injectors. As a pattern matures, increasing volumes of water are alternated with CO_2 injection to control gas break through and sweep efficiency. This process, referred to as “WAG” (Water Alternating Gas), typically results in the highest possible oil recovery; however, the production response can have a cyclical behavior during periods of high water injection. A number of patterns were cycled to water injection during the third quarter of 2010, which caused a normal slowing of oil response. During the same period, a failure of the hot oil system at the gas processing facility resulted in a sudden decrease of CO_2 injection. The combined effect of the increased water injection and loss of CO_2 injection resulted in the production decrease during the third quarter of 2010 as compared with the same period in 2009.

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The North Ward Estes field is located in Ward and Winkler Counties, Texas and is responding positively to our water and CO2 floods, which we initiated in May 2007. In early March 2009, we expanded the area of our CO2 injection project. Net production from the field increased 17% from 6.4 MBOE/d in the third quarter of 2009 to 7.5 MBOE/d in the third quarter of 2010. In this field, we are developing new and reactivated wells for water and CO2 injection and production purposes. Additionally, we plan to install oil, gas and water processing facilities in eight phases. The first two phases were largely completed by December 2009, and we estimate that Phase III-A will be substantially complete in the fourth quarter of 2010.

Acquisition Highlights. In September 2010, we acquired operated interests in 19 producing oil and gas wells, undeveloped acreage, and gathering lines, all of which are located on approximately 20,400 gross (16,100 net) acres in Weld County, Colorado. The aggregate unadjusted purchase price was $19.2 million, and substantially all of it was allocated to the properties and acreage acquired.

In August 2010, we acquired oil and gas leasehold interests covering approximately 112,000 gross (90,200 net) acres in the Montana portion of the Williston Basin for $26.0 million. The undeveloped acreage is located in Roosevelt and Sheridan counties.

Financing Highlights. In September 2010, we paid $383.5 million to redeem all of our $150.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2012 and all of our $220.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2013, which consisted of a redemption price of 100.00% for the 2012 notes and 101.8125% for the 2013 notes and included the payment of accrued and unpaid interest on such notes. We financed the redemption of the 2012 and 2013 notes with borrowings under our credit agreement. As a result of the redemption, we recognized a $6.2 million loss on early extinguishment of debt, which consisted of a cash charge of $4.0 million related to the redemption premium on the 2013 notes and a non-cash charge of $2.2 million related to the acceleration of debt discounts and unamortized debt issuance costs.

In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. We used the net proceeds from this issuance to repay a portion of the debt, which was borrowed to redeem our 2012 and 2013 notes, outstanding under our credit agreement.

In August 2010, we commenced an offer to exchange up to 3,277,500, or 95%, of our outstanding 6.25% convertible perpetual preferred stock ("preferred stock") for the following consideration per share of preferred stock: 2.3033 shares of our common stock and a cash premium of $14.50. The exchange offer expired in September 2010 and resulted in 3,277,500 shares of preferred stock being exchanged for the issuance of 7,549,010 shares of our common stock and a cash premium payment of $47.5 million. Following the exchange offer, the 3,277,500 shares of preferred stock accepted in the exchange were cancelled, and a total of 172,500 shares of preferred stock remained outstanding.

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Results of Operations

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Selected Operating Data:	Nine Months Ended September 30, 2010	2009
Net production:		
Oil (MMBbls)	14.0	11.3
Natural gas (Bcf)	20.1	22.6
Total production (MMBOE)	17.3	15.1
Net sales (in millions):		
Oil (1)	$967.7	$539.6
Natural gas (1)	101.3	77.0
Total oil and natural gas sales	$1,069.0	$616.6
Average sales prices:		
Oil (per Bbl)	$69.10	$47.79
Effect of oil hedges on average price (per Bbl)	(1.19)	0.07
Oil net of hedging (per Bbl)	$67.91	$47.86
Average NYMEX price (per Bbl)	$77.65	$57.13
Natural gas (per Mcf)	$5.05	$3.41
Effect of natural gas hedges on average price (per Mcf)	0.03	0.05
Natural gas net of hedging (per Mcf)	$5.08	$3.46
Average NYMEX price (per Mcf)	$4.59	$3.93
Cost and expense (per BOE):		
Lease operating expenses	$11.39	$11.78
Production taxes	$4.46	$2.87
Depreciation, depletion and amortization expense	$16.71	$20.04
General and administrative expenses	$2.80	$2.03

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $452.4 million to $1,069.0 million in the first nine months of 2010 compared to the same period in 2009. Sales are a function of oil and gas volumes sold and average sales prices. Our oil sales volumes increased 24% between periods, while our natural gas sales volumes decreased 11%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production at our two large CO_2 projects, Postle and North Ward Estes, partially offset by production decreases due to pipeline maintenance on the Enbridge system. Oil production from the Bakken in the first nine months of 2010 increased 2,225 MBbl compared to the first nine months of 2009, while North Ward Estes oil production increased 410 MBbl and Postle oil production increased 375 MBbl over the same prior year period. The gas volume decrease between periods was primarily the result of normal field production decline, which led to gas production decreases of 1,225 MMcf and 1,185 MMcf at our Boies Ranch and Kawitt areas, respectively, compared to the first nine months of 2009. These production decreases were partially offset by increased gas production of 1,100 MMcf in our North Dakota Bakken area. Also contributing to the increase in oil and natural gas sales revenue in 2010 were increases in average sales prices. Our average price for oil before the effects of hedging increased 45% between periods, and our average price for natural gas before the effects of hedging increased 48%. In addition to higher average NYMEX pricing during the first nine months of 2010 as compared to the same period in 2009, natural gas sales price increases were also due to fixed-price gas contracts entered into at our Flat Rock and Boies Ranch areas that carried a weighted-average price of $5.35 per Mcf for the first nine months of 2010. These contracts were in effect starting in the latter portion of the fourth quarter of 2009.

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Gain on Hedging Activities. Our gain on hedging activities decreased $8.4 million in 2010 as compared to the first nine months of 2009. The components of our gain on hedging activities were as follows (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Gains reclassified from AOCI on de-designated hedges	$ 19,641	$ 14,622
Realized cash settlement gains on crude oil derivatives	-	13,450
Total	$ 19,641	$ 28,072

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. Prior to April 1, 2009, however, realized cash settlements gains or losses on hedge-designated crude oil derivatives were also included in gain on hedging activities.

See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of October 15, 2010.

Lease Operating Expenses. Our lease operating expenses ("LOE") during the first nine months of 2010 were $197.6 million, a $20.2 million increase over the same period in 2009. This higher amount of LOE in 2010 was related to increases of $5.3 million in transportation charges, $4.9 million in ad valorem taxes and $3.8 million in electricity costs between periods, as well as a higher level of workover activity. The increase in transportation charges was primarily due to higher transportation fees on non-operated properties in the Bakken. Workovers amounted to $48.4 million in the first nine months of 2010, as compared to $37.8 million in the first nine months of 2009, and this increase in workover activity primarily related to our two CO2 projects. Our lease operating expenses on a BOE basis, however, decreased from $11.78 during the first nine months of 2009 to $11.39 during the first nine months of 2010. This decrease of 3% on a BOE basis was primarily the result of the increase in overall production volumes between periods.

Production Taxes. Our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of credits and exemptions allowed in our various taxing jurisdictions. Our production taxes during the first nine months of 2010 were $77.3 million, a $34.1 million increase over the same period in 2009, primarily due to higher oil and natural gas sales between periods. Our company-wide production tax rates for the first nine months of 2010 and 2009 were 7.2% and 7.0%, respectively, of oil and natural gas sales. Our production tax rate for the first nine months of 2010 was greater than the rate for same period in 2009 mainly due to successful wells completed during the fourth quarter of 2009 and the first nine months of 2010 in the North Dakota Bakken area, which has an 11.5% production tax rate.

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Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense decreased $11.8 million in 2010 as compared to the first nine months of 2009. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Depletion	$282,844	$293,869
Depreciation	1,571	2,370
Accretion of asset retirement obligations	5,421	5,383
Total	$289,836	$301,622

DD&A decreased in the first nine months of 2010 primarily due to $11.0 million in lower depletion expense between periods. This net decrease in depletion of $11.0 million was the result of $55.9 million in lower depletion expense due to a decline in our depletion rate between periods, which effect was largely offset by $44.9 million of additional depletion expense due to higher overall production volumes during the first nine months of 2010. On a BOE basis, our DD&A rate of $16.71 for the first nine months of 2010 was 17% lower than the rate of $20.04 for the same period in 2009. The primary factors causing this lower DD&A rate was a net increase in our estimated proved reserves of 35.9 MMBOE as of December 31, 2009, as well as proved developed and total proved reserves added during the first nine months of 2010. This factor was partially offset by (i) $607.9 million in drilling and development expenditures incurred during the past twelve months and (ii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $1.6 million in the first nine months of 2010, as compared to the first nine months of 2009. The components of our exploration and impairment costs were as follows (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Exploration	$25,861	$24,785
Impairment	12,054	14,743
Total	$37,915	$39,528

Exploration costs increased $1.1 million during the first nine months of 2010 as compared to the same period in 2009 primarily due to an increase in geological and geophysical ("G&G") activity, increased accrued Production Participation Plan ("the Plan") payments for G&G personnel and higher exploratory dry hole costs, partially offset by reduced rig termination fees. G&G costs amounted to $12.0 million during the first nine months of 2010 as compared to $6.2 million during the same period in 2009. Accrued Plan distributions for exploration personnel were $1.3 million higher during the first nine months of 2010 as compared to the same prior year period primarily due to a higher level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) resulting from higher overall production and higher oil and natural gas prices during the first nine months of 2010 as compared to the same period in 2009. These increases were partially offset by reduced rig termination fees recognized in the first nine months of 2010. No rig termination fees were paid during the first nine months of 2010, while rig termination fees totaled $6.5 million during the first nine months of 2009.

The impairment charges in the first nine months of 2010 and 2009 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. The decrease of $2.7 million in impairment expense between periods, however, was mainly due to $3.1 million in non-cash impairment charges in the first nine months of 2009 for the partial write-down of certain proved properties whose net book values exceeded their undiscounted future cash flows. There were no proved property impairment charges during the first nine months of 2010.

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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,	
	2010	2009
General and administrative expenses	$88,372	$68,100
Reimbursements and allocations	(39,856)	(37,524)
General and administrative expense, net	$48,516	$30,576

General and administrative expenses before reimbursements and allocations increased $20.3 million during the first nine months of 2010 as compared to the same period in 2009 primarily due to an increase in accrued Plan distributions, higher employee compensation and 2010 offering costs related to the 6.25% convertible perpetual preferred stock exchange offer. The largest component of the increase related to $12.2 million in higher accrued distributions under the Plan between periods. Employee compensation increased $7.6 million in the first nine months of 2010 due to higher stock compensation between periods, personnel hired during the past twelve months and general pay increases. In addition, we incurred $2.2 million of offering costs in 2010 related to the preferred stock exchange offer completed in September. The increase in reimbursements and allocations in the first nine months of 2010 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 2010 and 2009.

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

	Nine Months Ended September 30,	
	2010	2009
Senior Subordinated Notes	$31,972	$32,826
Credit agreement	6,704	10,589
Amortization of debt issue costs and debt discount	8,525	8,143
Other	142	139
Capitalized interest	(1,440)	(2,677)
Total	$45,903	$49,020

The decrease in interest expense of $3.1 million between periods was mainly due to lower borrowings outstanding under our credit agreement during the first nine months of 2010, which reduced the interest on our credit agreement by $3.9 million. In addition, we incurred lower interest on our Senior Subordinated Notes due to the redemption of $150.0 million of 7.25% notes due 2012 and $220.0 million of 7.25% notes due 2013 in early September 2010, and then at the end of September 2010, we subsequently issued $350.0 million of 6.5% notes due 2018. These decreases in interest were partially offset by lower amounts of capitalized interest between periods. Our weighted average debt outstanding during the first nine months of 2010 was $721.4 million versus $1,080.8 million for the first nine months of 2009. Our weighted average effective cash interest rate was 7.2% during the first nine months of 2010 compared to 5.4% during the first nine months of 2009.

Commodity Derivative (Gain) Loss, Net. During the past three years, we entered into commodity derivative contracts that we did not designate as cash flow hedges. In addition, 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, beginning April 1, 2009 all of our derivative contracts are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings. Cash flow is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded immediately to earnings as commodity derivative (gain) loss, net.

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The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Change in unrealized (gains) losses on derivative contracts	$(62,571)	$137,616
Realized cash settlement losses	15,917	11,635
Loss on hedging ineffectiveness	-	22,655
Total	$(46,654)	$171,906

The change in unrealized (gains) losses on derivative contracts increased by $200.2 million between periods due to the fact that (i) there was a significant downward shift in the forward price curve for NYMEX crude oil during the nine months ended September 30, 2010 as compared to the upward shift in the same forward price curve during the nine months ended September 30, 2009, and (ii) we averaged 18.3 MMBbls of crude oil hedged during the nine months ended September 30, 2010, while we averaged 20.5 MMBbls of crude oil hedged during the nine months ended September 30, 2009. During the first quarter of 2009, we recognized a loss of $22.7 million for the ineffective portion of changes in fair value on our commodity derivatives then designated as cash flow hedges.

Income Tax Expense (Benefit). Income tax expense totaled $165.9 million for the first nine months of 2010, as compared to a $51.8 million income tax benefit for the first nine months of 2009. Our effective income tax rate increased from 33.9% for the first nine months of 2009 to 38.0% for the first nine months of 2010. The change in the effective income tax rate between periods was primarily due to the change from net loss in 2009 to net income in 2010.

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Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009

Selected Operating Data:	Three Months Ended September 30, 2010	2009
Net production:		
Oil (MMBbls)	4.9	3.9
Natural gas (Bcf)	6.9	7.1
Total production (MMBOE)	6.1	5.1
Net sales (in millions):		
Oil (1)	$330.8	$232.3
Natural gas (1)	34.4	23.8
Total oil and natural gas sales	$365.2	$256.1
Average sales prices:		
Oil (per Bbl)	$67.02	$58.86
Effect of oil hedges on average price (per Bbl)	(0.92)	(2.42)
Oil net of hedging (per Bbl)	$66.10	$56.44
Average NYMEX price (per Bbl)	$76.21	$68.29
Natural gas (per Mcf)	$5.00	$3.35
Effect of natural gas hedges on average price (per Mcf)	0.02	0.05
Natural gas net of hedging (per Mcf)	$5.02	$3.40
Average NYMEX price (per Mcf)	$4.39	$3.40
Cost and expense (per BOE):		
Lease operating expenses	$11.34	$11.46
Production taxes	$4.31	$3.66
Depreciation, depletion and amortization expense	$16.06	$19.74
General and administrative expenses	$3.20	$2.21

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $109.2 million to $365.2 million in the third quarter of 2010 compared to the same period in 2009. Sales are a function of oil and gas volumes sold and average sales prices. Our oil sales volumes increased 25% between periods, while our natural gas sales volumes decreased 3%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production at our two large CO_2 projects, Postle and North Ward Estes, partially offset by production decreases due to pipeline maintenance on the Enbridge system. Oil production from the Bakken increased 880 MBbl compared to the third quarter of 2009, while North Ward Estes oil production increased 115 MBbl and Postle oil production increased 60 MBbl in the third quarter of 2010 over the same prior year period. The gas volume decrease between periods was primarily the result of normal field production decline, which led to gas production decreases of 280 MMcf and 260 MMcf at our Kawitt and Boies Ranch areas, respectively, for the third quarter of 2010 when compared to the third quarter of 2009. These production decreases were partially offset by increased gas production of 320 MMcf in our North Dakota Bakken area and 190 MMcf in our Flat Rock area. Also contributing to the increase in oil and natural gas sales revenue in 2010 were increases in average sales prices. Our average price for oil before the effects of hedging increased 14% between periods, and our average price for natural gas before the effects of hedging increased 49%. In addition to higher average NYMEX pricing during the third quarter of 2010 as compared to the same period in 2009, natural gas sales price increases were also due to fixed-price gas contracts entered into at our Flat Rock and Boies Ranch areas that carried a weighted-average price of $5.33 per Mcf for the third quarter of 2010. These contracts were in effect starting in the latter portion of the fourth quarter of 2009.

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Gain on Hedging Activities. 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. As a result, we reclassified from AOCI into earnings $4.4 million and $7.8 million in 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 in the third quarter of 2010 and 2009, respectively. See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of October 15, 2010.

Lease Operating Expenses. Our lease operating expenses during the third quarter of 2010 were $69.0 million, a $10.2 million increase over the same period in 2009. This higher amount of LOE in 2010 was related to increases of $2.0 million in transportation charges, $1.6 million in electricity costs and $1.5 million in ad valorem taxes between periods, as well as a higher level of workover activity. The increase in transportation charges was primarily due to higher transportation fees on non-operated properties in the Bakken. Workovers amounted to $17.4 million in the third quarter of 2010, as compared to $11.6 million in the third quarter of 2009, and this increase in workover activity primarily related to our two CO2 projects. Our lease operating expenses on a BOE basis decreased from $11.46 during the third quarter of 2009 to $11.34 during the third quarter of 2010. The decrease of 1% on a BOE basis was the result of the increase in overall production volumes between periods.

Production Taxes. Our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of credits and exemptions allowed in our various taxing jurisdictions. Our production taxes during the third quarter of 2010 were $26.2 million, a $7.4 million increase over the same period in 2009, primarily due to higher oil and natural gas sales between periods. Our company-wide production tax rates for the third quarter of 2010 and 2009 were 7.2% and 7.3%, respectively, of oil and natural gas sales.

Depreciation, Depletion and Amortization. Our DD&A expense decreased $3.6 million in 2010 as compared to the third quarter of 2009. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30,	
	2010	2009
Depletion	$95,276	$98,876
Depreciation	565	771
Accretion of asset retirement obligations	1,863	1,626
Total	$97,704	$101,273

DD&A decreased in the third quarter of 2010 primarily due to $3.6 million in lower depletion expense between periods. This net decrease in depletion was the result of $22.0 million in lower depletion expense due to a decline in our depletion rate between periods, which effect was largely offset by $18.4 million of additional depletion expense due to higher overall production volumes during the third quarter of 2010. On a BOE basis, our DD&A rate of $16.06 for the third quarter of 2010 was 19% lower than the rate of $19.74 for the same period in 2009. The primary factors causing this lower DD&A rate was a net increase in our estimated proved reserves of 35.9 MMBOE as of December 31, 2009, as well as proved developed and total proved reserves added during the first nine months of 2010. This factor was partially offset by (i) $607.9 million in drilling and development expenditures incurred during the past twelve months and (ii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

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Exploration and Impairment Costs. Our exploration and impairment costs decreased $1.9 million in the third quarter of 2010, as compared to the third quarter of 2009. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended September 30,	
	2010	2009
Exploration	$6,145	$5,973
Impairment	4,355	6,449
Total	$10,500	$12,422

Exploration costs increased $0.2 million during the third quarter of 2010 as compared to the same period in 2009 primarily due to an increase in G&G activity, partially offset by lower exploratory dry hole costs in the third quarter of 2010.

The impairment charges in the third quarter of 2010 and 2009 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. The decrease of $2.1 million in impairment expense between periods, however, was mainly due to a $2.3 million non-cash impairment charge in the third quarter of 2009 for the partial write-down of certain proved properties whose net book values exceeded their undiscounted future cash flows. There were no proved property impairment charges during the third quarter of 2010.

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,	
	2010	2009
General and administrative expenses	$32,980	$24,417
Reimbursements and allocations	(13,500)	(13,103)
General and administrative expense, net	$19,480	$11,314

General and administrative expenses before reimbursements and allocations increased $8.6 million to $33.0 million during the third quarter of 2010. The largest component of the increase related to $3.5 million in additional employee compensation in the third quarter of 2010 related to higher stock compensation between periods, personnel hired during the past twelve months and general pay increases. In addition to these higher employee compensation costs, there was $2.7 million in higher accrued distributions under the Plan between periods, and we incurred $2.2 million of offering costs in 2010 related to the preferred stock exchange offer completed in September. The increase in reimbursements and allocations in the third quarter of 2010 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 increased from 4% for the third quarter of 2009 to 5% for the third quarter of 2010.

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

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009
Senior Subordinated Notes	$9,810	$11,081
Credit agreement	2,596	2,436
Amortization of debt issue costs and debt discount	2,801	2,968
Other	29	26
Capitalized interest	(657)	(864)
Total	$14,579	$15,647

The decrease in interest expense of $1.1 million between periods was mainly due to the redemption of $150.0 million of 7.25% notes due 2012 and $220.0 million of 7.25% notes due 2013 in early September 2010, and then at the end of September 2010 we subsequently issued $350.0 million of 6.5% notes due 2018. Together these refinancing transactions had the aggregate effect of reducing the interest on our Senior Subordinated Notes between periods by $1.3 million. Our weighted average debt outstanding during the third quarter of 2010 was $674.7 million versus $824.9 million for the third quarter of 2009. Our weighted average effective cash interest rate was 7.4% during the third quarter of 2010 compared to 6.6% during the third quarter of 2009.

Commodity Derivative (Gain) Loss, Net. During the third quarter of 2010 and 2009, all of our derivative contracts were marked-to-market each quarter with fair value gains and losses recognized immediately in earnings. Cash flow is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded immediately to earnings as commodity derivative (gain) loss, net.

The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009
Change in unrealized (gains) losses on derivative contracts	$27,407	$(19,567)
Realized cash settlement losses	4,358	9,176
Total	$31,765	$(10,391)

The change in unrealized (gains) losses on derivative contracts increased by $47.0 million between periods due to the fact that there was a significant upward shift in the forward price curve for NYMEX crude oil during the three months ended September 30, 2010 as compared to the downward shift in the same forward price curve during the three months ended September 30, 2009.

Income Tax Expense (Benefit). Income tax expense totaled $35.9 million for the third quarter of 2010, as compared to $26.3 million for the third quarter of 2009. Our effective income tax rate decreased from 42.3% for the third quarter of 2009 to 38.0% for the third quarter of 2010. The change in the effective income tax rate between periods was primarily due to the change from net loss in 2009 to net income in 2010.

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Liquidity and Capital Resources

Overview. At September 30, 2010, our debt to total capitalization ratio was 22.1%, we had $3.2 million of cash on hand and $2,465.4 million of stockholders' equity. At December 31, 2009, our debt to total capitalization ratio was 25.6%, we had $12.0 million of cash on hand and $2,270.1 million of stockholders' equity. In the first nine months of 2010, we generated $720.3 million of cash provided by operating activities, an increase of $429.4 million over the same period in 2009. Cash provided by operating activities increased primarily due to higher oil production volumes and higher average sales prices for both crude oil and natural gas. These positive factors were partially offset by lower gas production volumes in the first nine months of 2010, as well as increased production taxes, lease operating expenses and general and administrative expenses during the first nine months of 2010 as compared to the same period in 2009. Cash flows from operating activities were used to finance $473.7 million of drilling and development expenditures and $102.3 million of cash acquisition capital expenditures paid in the first nine months of 2010, net repayments under our credit agreement totaling $60.0 million, the premium of $47.5 million for the induced conversion of our convertible perpetual preferred stock and the payment of preferred stock dividends totaling $16.2 million. The following chart details our exploration and development expenditures incurred by region during the first nine months of 2010 (in thousands):

	Drilling and Development Expenditures (1)	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$322,273	$12,630	$334,903	62%
Permian Basin	143,431	7,963	151,394	28%
Mid-Continent	31,171	1,224	32,395	6%
Gulf Coast	12,564	3,990	16,554	3%
Michigan	5,146	54	5,200	1%
Total incurred	514,585	25,861	540,446	100%
Increase in accrued capital expenditures	(43,684)	-	(43,684)	
Total paid	$470,901	$25,861	$496,762	

(1) For purposes of this schedule, exploratory dry hole costs of $2.8 million are excluded from drilling and development expenditures as reported on the statement of cash flows and instead have been included in exploration expenditures above.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2010 capital budget for exploration and development expenditures is $830.0 million, which we expect to fund with net cash provided by our operating activities. Our 2010 capital budget of $830.0 million represents a significant increase from the $479.8 million incurred on exploration and development expenditures during 2009. This increased capital budget is due to increased discretionary cash flow resulting primarily from higher oil and natural gas prices experienced during the second half of 2009 and continuing into the first nine months of 2010, along with our available inventory of high-quality prospects for development and exploration. Although we have no specific budget for property acquisitions in 2010, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that if attractive acquisition opportunities arise or exploration and development expenditures exceed $830.0 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, or agreements with industry partners. Our level of exploration and development 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, dividend distributions 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. As of September 30, 2010, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), our wholly-owned subsidiary, had a credit agreement with a syndicate of banks, and this credit facility had a borrowing base of $1.1 billion with $999.6 million of available borrowing capacity, which was net of $100.0 million in borrowings and $0.4 million in letters of credit outstanding. At September 30, 2010, the effective weighted average interest rate on the outstanding principal balance under the credit facility was 2.3%, and we were in compliance with our covenants under the credit agreement.

In October 2010, we entered into a Fifth Amended and Restated Credit Agreement with our bank syndicate, which replaced the existing credit agreement. This amended credit agreement maintained the borrowing base of $1.1 billion and extended the principal repayment date from April 2012 to October 2015. The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the 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.

The amended credit agreement provides for interest only payments until October 2015, 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.

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

Under the amended credit agreement, we also incur commitment fees of 0.50% on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base.

The amended terms of 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. 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 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. Except for limited exceptions, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, the credit agreement restricts our ability to make any dividend payments or distributions on our common stock.

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. We have guaranteed the obligations of Whiting Oil and Gas under the credit agreement and have pledged the stock of Whiting Oil and Gas as security for our guarantee.

Senior Subordinated Notes. In September 2010, we paid $383.5 million to redeem all of our $150.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2012 and all of our $220.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2013, which consisted of a redemption price of 100.00% for the 2012 notes and 101.8125% for the 2013 notes and included the payment of accrued and unpaid interest on such notes. We financed the redemption of the 2012 and 2013 notes with borrowings under our credit agreement. As a result of the redemption, we recognized a $6.2 million loss on early extinguishment of debt, which consisted of a cash charge of $4.0 million related to the redemption premium on the 2013 notes and a non-cash charge of $2.2 million related to the acceleration of debt discounts and unamortized debt issuance costs.

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In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. We used the net proceeds from this issuance to repay a portion of the debt, which was borrowed to redeem our 2012 and 2013 notes, outstanding under our credit agreement. 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, 2010. However, a substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Schedule of Contractual Obligations. The table below does not include our September 30, 2010 Production Participation Plan liability of $79.0 million, since we cannot determine with accuracy the timing or amounts of future payments. The following table summarizes our obligations and commitments as of September 30, 2010 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)	$ 700,000	$ -	$ 100,000	$ 250,000	$ 350,000
Cash interest expense on debt (b)	243,899	42,510	81,806	51,333	68,250
Asset retirement obligation (c)	79,662	5,740	4,995	9,617	59,310
Tax sharing liability (d)	23,651	1,857	3,320	18,474	-
Derivative contract liability fair value (e)	124,682	33,432	85,320	5,930	-
Purchasing obligations (f)	127,309	41,106	70,211	15,992	-
Drilling rig contracts (g)	117,804	42,725	64,634	10,445	-
Operating leases (h)	10,132	3,508	6,367	257	-
Total	$ 1,427,139	$ 170,878	$ 416,653	$ 362,048	$ 477,560

(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, and assumes no principal repayment until the due date of the 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 date of the instruments. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the instrument due date and is estimated at a fixed interest rate of 2.3%.

(c) 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.

(d) 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.

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(e) The above derivative obligation at September 30, 2010 consists of a $115.1 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. With respect to our open derivative contracts at September 30, 2010 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. The above derivative obligation at September 30, 2010 also consists of a $9.6 million payable to Whiting USA Trust I (the "Trust") for derivative contracts that we have entered into but have in turn conveyed to the Trust. Although these derivatives are in a fair value asset position at quarter end, 75.8% of such derivative assets are due to the Trust under the terms of the conveyance.

(f) We have two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement expiring in December 2014, whereby we have committed to buy certain volumes of CO2 for use in enhanced recovery projects in our Postle field in Oklahoma and our North Ward Estes field in Texas. The purchase agreements are with 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 a ship-or-pay agreement expiring in June 2013, whereby we have committed to transport a minimum daily volume of CO2 via the Transpetco pipeline 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 these agreements. Therefore, we expect to avoid any payments for deficiencies.

(g) We currently have seven drilling rigs under long-term contract, of which one drilling rig expires in 2010, one in 2011, two in 2012, one in 2013 and two in 2014. All of these rigs are operating in the Rocky Mountains region. As of September 30, 2010, early termination of the remaining contracts would require termination penalties of $75.0 million, which would be in lieu of paying the remaining drilling commitments of $117.8 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 116,100 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, and an additional 46,700 square feet of office space in Midland, Texas expiring in 2012.

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.

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, 2009.

Effects of Inflation and Pricing

We experienced increased costs during 2007 and 2008 due to increased demand for oil field products and services, while costs in 2009 remained relatively consistent with 2008. During the first nine months of 2010, we began to experience moderate cost increases, as the demand for oil field products and services has begun to rise from 2009 levels. 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.

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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 or natural gas prices; impacts of the global recession and tight credit markets; our level of success in exploitation, exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures, including our ability to obtain CO2; 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; 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; federal and state initiatives relating to hydraulic fracturing; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption “Risk Factors” in this Quarterly Report on Form 10-Q. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2009 and have not materially changed since that report was filed.

Our outstanding hedges as of October 15, 2010 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	10/2010 to 12/2010	795,000	$63.82/$88.95
Crude Oil	01/2011 to 03/2011	795,000	$59.72/$94.74
Crude Oil	04/2011 to 06/2011	795,000	$59.72/$94.74
Crude Oil	07/2011 to 09/2011	795,000	$59.72/$94.74
Crude Oil	10/2011 to 12/2011	795,000	$59.72/$94.74
Crude Oil	01/2012 to 03/2012	330,000	$47.46/$90.19
Crude Oil	04/2012 to 06/2012	330,000	$47.46/$90.19
Crude Oil	07/2012 to 09/2012	330,000	$47.46/$90.19
Crude Oil	10/2012 to 12/2012	330,000	$47.46/$90.19
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

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (the “Trust”), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 1,035 MBbl of crude oil and 3,880 MMcf of natural gas from 2010 through 2012, have been conveyed to the Trust, and therefore such payments will be included in the Trust’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 units, results in third-party public holders of Trust 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 assets.

The table below summarizes all of the costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Whiting USA Trust I (of which we retain 24.2% of the future economic results and third-party public holders of Trust units receive 75.8% of the future economic results):

Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	10/2010 to 12/2010	41,924	$76.00/$135.11
Crude Oil	01/2011 to 03/2011	40,978	$74.00/$139.68
Crude Oil	04/2011 to 06/2011	40,066	$74.00/$140.08

Crude Oil	07/2011 to 09/2011	39,170	$74.00/$140.15
Crude Oil	10/2011 to 12/2011	38,242	$74.00/$140.75
Crude Oil	01/2012 to 03/2012	37,412	$74.00/$141.27
Crude Oil	04/2012 to 06/2012	36,572	$74.00/$141.73
Crude Oil	07/2012 to 09/2012	35,742	$74.00/$141.70
Crude Oil	10/2012 to 12/2012	35,028	$74.00/$142.21
Natural Gas	10/2010 to 12/2010	162,997	$7.00/$14.20
Natural Gas	01/2011 to 03/2011	157,600	$7.00/$17.40
Natural Gas	04/2011 to 06/2011	152,703	$6.00/$13.05
Natural Gas	07/2011 to 09/2011	148,163	$6.00/$13.65
Natural Gas	10/2011 to 12/2011	142,787	$7.00/$14.25
Natural Gas	01/2012 to 03/2012	137,940	$7.00/$15.55
Natural Gas	04/2012 to 06/2012	134,203	$6.00/$13.60
Natural Gas	07/2012 to 09/2012	130,173	$6.00/$14.45
Natural Gas	10/2012 to 12/2012	126,613	$7.00/$13.40

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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 contracts listed in both tables above, a hypothetical $5.00 per Bbl change in the NYMEX forward curve as of September 30, 2010 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $50.6 million. For the natural gas contracts listed above, a hypothetical $1.00 per Mcf change in the NYMEX forward curve as of September 30, 2010 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $0.7 million.

We have various fixed-price 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 15, 2010 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	10/2010 to 12/2010	823,178	$5.29
Natural Gas	01/2011 to 03/2011	776,721	$5.30
Natural Gas	04/2011 to 06/2011	777,767	$5.31
Natural Gas	07/2011 to 09/2011	771,506	$5.30
Natural Gas	10/2011 to 12/2011	771,506	$5.30
Natural Gas	01/2012 to 03/2012	576,173	$5.30
Natural Gas	04/2012 to 06/2012	460,506	$5.41
Natural Gas	07/2012 to 09/2012	464,840	$5.41
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

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Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our 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, 2010. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of September 30, 2010 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, 2010 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. We believe that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2009, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

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

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

- changes in global supply and demand for oil and gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity;
- the level of global oil and gas exploration and production activity;
- the level of global oil and gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and gas in captive market areas; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve bookings. 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, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending or borrow any such shortfall. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement.

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The global recession and tight financial markets may have impacts on our business and financial condition that we currently cannot predict.

The current global recession and tight credit financial markets may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection.

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

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

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and CO_2;
- equipment failures or accidents;
- adverse weather conditions, such as freezing temperatures, hurricanes and storms;
- reductions in oil and natural gas prices; and
- title problems.

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

As of December 31, 2009, undeveloped reserves comprised 47% of the North Ward Estes field's total estimated proved reserves and 18% of the Postle field's total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $573.9 million at the North Ward Estes field and $44.4 million at the Postle field as of December 31, 2009. Together, these fields encompass 56% of our total estimated future development costs of $1,103.2 million related to proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO_2 injection installations, the success of which is less predictable than traditional development techniques. Therefore, ultimate recoveries from these fields may not match current expectations.

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

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO2 into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO2. Under our CO2 contracts, if the supplier suffers an inability to deliver its contractually required quantities of CO2 to us and other parties with whom it has CO2 contracts, then the supplier may reduce the amount of CO2 on a pro rata basis it provides to us and such other parties. If this occurs, we may not have sufficient CO2 to produce oil and natural gas in the manner or to the extent that we anticipate. These contracts are also structured as “take-or-pay” arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO2 as part of our enhanced recovery techniques.

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

We describe some of our current prospects and our plans to explore those prospects in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and our Annual Report on Form 10-K for the year ended December 31, 2009. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flow rates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, from more fully explored prospects, or from producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

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

Accounting rules require that we review periodically the carrying value of our oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, which may include depressed oil and natural gas prices, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and gas properties. For example, we recorded a $9.4 million impairment write-down during 2009 for the partial impairment of producing properties, primarily natural gas, in the Rocky Mountains region. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in our Annual Report on Form 10-K for the year ended December 31, 2009.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in our Annual Report on Form 10-K for the year ended December 31, 2009. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and current costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the estimate. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2009 would have decreased from $2,343.5 million to $2,335.5 million. If oil prices decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2009 would have decreased from $2,343.5 million to $2,286.3 million.

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

As of September 30, 2010, we had $100.0 million in borrowings and $0.4 million in letters of credit outstanding under Whiting Oil and Gas Corporation's credit agreement with $999.6 million of available borrowing capacity, as well as $600.0 million of senior subordinated notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's credit agreement.

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

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
-

limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;

- placing us at a competitive disadvantage relative to other less leveraged competitors;
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas Corporation's credit agreement may be at variable rates; and
- potentially limiting our ability to pay dividends in cash on our convertible perpetual preferred stock.

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

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

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

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

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

In addition, Whiting Oil and Gas Corporation's credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for 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. Also, the indentures under which we issued our senior subordinated notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. A substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants.

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

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

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

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

If our revenues or the borrowing base under our bank credit agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

Our acquisition activities may not be successful.

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

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

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

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

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

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2009, we had identified a drilling inventory of over 1,400 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, ability to extend drilling acreage leases beyond expiration, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For example, during the fourth quarter of 2008, we recorded a $10.9 million non-cash charge for the partial impairment of unproved properties in the central Utah Hingeline play. We may also incur such impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. Additionally, our rights to develop a portion of our undeveloped acreage may expire if not successfully developed or renewed. Out of a total of 773,300 gross (372,200 net) undeveloped acres as of December 31, 2009, the portion of our net undeveloped acres that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 14% in 2010, 18% in 2011 and 8% in 2012.

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

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes a continuing acquisition program. From 2004 through 2009, we completed 15 separate acquisitions of producing properties with a combined purchase price of $1,889.9 million for estimated proved reserves as of the effective dates of the acquisitions of 230.7 MMBOE. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

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

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

We enter into hedging transactions of our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas forward sales contracts, primarily costless collars, placed with major financial institutions. As of October 15, 2010, we had contracts, which include our 24.2% share of the Whiting USA Trust I hedges, covering the sale for the fourth quarter of 2010 of 805,146 barrels of oil per month and 39,445 MMBtu of natural gas per month. All our oil hedges will expire by November 2013 and all our natural gas hedges will expire by December 2012. See “Quantitative and Qualitative Disclosure about Market Risk” in this Quarterly Report on Form 10-Q for pricing and a more detailed discussion of our hedging transactions.

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

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges as of March 31, 2009 and have elected to discontinue hedge accounting prospectively. As such, subsequent to March 31, 2009 we recognize all gains and losses from prospective changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income. Subsequently, we may experience significant net income and operating result losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility.

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

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

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

The prices that we receive for our oil and natural gas production generally trade at a discount to the relevant benchmark prices such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

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

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

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

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

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

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

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

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

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

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

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

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

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

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

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

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

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Changes in environmental laws and regulations occur frequently and may serve to have a materially adverse impact on our business. For example, as a result of the explosion and fire on the Deepwater Horizon drilling rig in April 2010 and the release of oil from the Macondo well in the Gulf of Mexico, there has been a variety of governmental regulatory initiatives to make more stringent or otherwise restrict oil and natural gas drilling operations in certain locations. Any increased governmental regulation or suspension of oil and natural gas exploration or production activities that arises out of these incidents could result in higher operating costs, which could, in turn, adversely affect our operating results. Also, for instance, any changes in laws or regulations that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position, or financial condition as well as those of the oil and gas industry in general.

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

On December 15, 2009, the U.S. Environmental Protection Agency, or EPA, published its findings that emissions of carbon dioxide, methane, and other greenhouse gases, or “GHGs,” present an endangerment to public heath and the environment because emissions of such gasses are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards take effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (“PSD”) and Title V permitting programs. This rule “tailors” these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to “best available control technology” standards for GHG that have yet to be developed. In addition, in April 2010, the EPA proposed to expand its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. If the proposed rule is finalized as proposed, reporting of GHG emissions from such facilities would be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

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

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

The U.S. Congress is considering legislation that would amend the federal Safe Drinking Water Act by repealing an exemption for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing is an important and commonly used process for the completion of natural gas, and to a lesser extent, oil wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate natural gas production. Sponsors of the legislation have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. If enacted, the legislation could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. The legislation also proposes requiring the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities, who would then make such information publicly available. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any federal or state legislation or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

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

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

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

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

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

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

In February 2010, President Obama's Administration released its proposed federal budget for fiscal year 2011 that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to:

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

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

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

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

Item 5. Other Information

Amendments to Articles of Incorporation or Bylaws; Change in Fiscal Year. On October 26, 2010, Whiting filed a Certificate of Decrease with the Secretary of State of the State of Delaware decreasing the number of authorized shares of its 6.25% convertible perpetual preferred stock (the "Preferred Stock") by a total of 3,277,500. The shares of Preferred Stock were acquired by Whiting as a result of an exchange offer that closed in September 2010 to exchange 7,549,010 shares of its common stock and approximately $47.5 million for the 3,277,500 shares of Preferred Stock. Upon the filing of the Certificate of Decrease, such shares of Preferred Stock reverted back to authorized but unissued shares of preferred stock and, after such decrease, 172,500 shares of Preferred Stock remained authorized. The Certificate of Decrease is filed herewith as Exhibit 3.1 and incorporated herein by reference.

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On October 26, 2010, Whiting filed a Restated Certificate of Incorporation, which incorporated all amendments made to Whiting's Amended and Restated Certificate of Incorporation. The Restated Certificate of Incorporation is filed herewith as Exhibit 3.2 and incorporated herein by reference.

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 29th day of October, 2010.

WHITING PETROLEUM CORPORATION

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

By /s/ Michael J. Stevens
Michael J. Stevens
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
(3.1)	Certificate of Decrease of Whiting Petroleum Corporation.
(3.2)	Restated Certificate of Incorporation of Whiting Petroleum Corporation.
(4.1)	Fifth Amended and Restated Credit Agreement, dated as of October 15, 2010, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the various other agents party thereto [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 15, 2010 (File No. 001-31899)].
(4.2)	Second Supplemental Indenture, dated September 24, 2010, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating the 6.5% Senior Subordinated Notes due 2018 [Incorporated by reference to Exhibit 4.2 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 21, 2010 (File No. 001-31899)].
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the 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, 2010 are furnished herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of September 30, 2010 and December 31, 2009, (ii) the Consolidated Statements of Income for Three and Nine Months Ended September 30, 2010 and 2009, (iii) the Consolidated Statements of Cash Flow for the Nine Months Ended September 30, 2010 and 2009, (iv) the Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Nine Months Ended September 30, 2010 and 2009, and (v) Notes to Consolidated Financial Statements.