WHITING PETROLEUM CORP
Form 10-Q
October 29, 2009

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, 2009

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 £ 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, 2009: 50,845,106 shares.

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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” - One thousand BOE.

“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.

“MMcf/d” - One MMcf of natural gas per day.

“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)

ASSETS	September 30, 2009	December 31, 2008
CURRENT ASSETS:		
Cash and cash equivalents	$15,860	$9,624
Accounts receivable trade, net	127,063	123,386
Derivative assets	7,803	46,780
Prepaid expenses and other	7,222	37,284
Total current assets	157,948	217,074
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	4,708,604	4,423,197
Unproved properties	99,135	106,436
Other property and equipment	112,920	91,099
Total property and equipment	4,920,659	4,620,732
Less accumulated depreciation, depletion and amortization	(1,178,667)	(886,065)
Total property and equipment, net	3,741,992	3,734,667
DEBT ISSUANCE COSTS	27,186	10,779
DERIVATIVE ASSETS	12,778	38,104
OTHER LONG-TERM ASSETS	23,585	28,457
TOTAL	$3,963,489	$4,029,081

See notes to consolidated financial statements. (Continued)

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

LIABILITIES AND STOCKHOLDERS' EQUITY	September 30, 2009	December 31, 2008
CURRENT LIABILITIES:		
Accounts payable	$18,326	$64,610
Accrued capital expenditures	23,372	84,960
Accrued liabilities	61,858	45,359
Accrued interest	20,285	9,673
Oil and gas sales payable	35,990	35,106
Accrued employee compensation and benefits	15,461	41,911
Production taxes payable	21,568	20,038
Deferred gain on sale	13,195	14,650
Derivative liabilities	25,050	17,354
Deferred income taxes	10,305	15,395
Tax sharing liability	2,112	2,112
Total current liabilities	247,522	351,168
NON-CURRENT LIABILITIES:		
Long-term debt	769,604	1,239,751
Deferred income taxes	351,409	390,902
Deferred gain on sale	62,181	73,216
Production Participation Plan liability	69,168	66,166
Asset retirement obligations	67,176	47,892
Derivative liabilities	86,197	28,131
Tax sharing liability	22,802	21,575
Other long-term liabilities	2,980	1,489
Total non-current liabilities	1,431,517	1,869,122
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 3,450,000 and 0 shares issued and outstanding as of September 30, 2009 and December 31, 2008, respectively, aggregate liquidation preference of $345,000,000	3	-
Common stock, $0.001 par value, 75,000,000 shares authorized; 51,363,728 issued and 50,845,106 outstanding as of September 30, 2009, 42,582,100 issued and 42,323,336 outstanding as of December 31, 2008	51	43
Additional paid-in capital	1,543,037	971,310
Accumulated other comprehensive income	27,170	17,271
Retained earnings	714,189	820,167
Total stockholders' equity	2,284,450	1,808,791
	$3,963,489	$4,029,081

TOTAL	

See notes to consolidated financial statements. (Concluded)

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 256,074	$ 425,392	$ 616,552	$ 1,102,658
Gain (loss) on hedging activities	7,774	(41,879)	28,072	(112,902)
Amortization of deferred gain on sale	4,222	4,720	12,595	7,677
Gain on sale of properties	1,101	-	5,709	-
Interest income and other	156	201	396	825
Total revenues and other income	269,327	388,434	663,324	998,258
COSTS AND EXPENSES:				
Lease operating	58,807	64,690	177,343	177,866
Production taxes	18,792	28,245	43,225	71,988
Depreciation, depletion and amortization	101,273	74,233	301,622	179,555
Exploration and impairment	12,422	10,939	39,528	30,566
General and administrative	11,314	17,281	30,576	51,903
Interest expense	15,647	17,543	49,020	48,760
Change in Production Participation Plan liability	(678)	9,117	3,002	26,964
Commodity derivative (gain) loss, net	(10,391)	(10,561)	171,906	7,064
Total costs and expenses	207,186	211,487	816,222	594,666
INCOME (LOSS) BEFORE INCOME TAXES	62,141	176,947	(152,898)	403,592
INCOME TAX EXPENSE (BENEFIT):				
Current	(507)	481	(1,046)	1,353
Deferred	26,793	64,049	(50,785)	147,060
Total income tax expense (benefit)	26,286	64,530	(51,831)	148,413
NET INCOME (LOSS)	35,855	112,417	(101,067)	255,179
Preferred stock dividends declared	(4,911)	-	(4,911)	-
	$ 30,944	$ 112,417	$ (105,978)	$ 255,179

NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS				
NET INCOME (LOSS) PER COMMON SHARE, BASIC	$ 0.59	$ 2.66	$ (2.15)	$ 6.03
NET INCOME (LOSS) PER COMMON SHARE, DILUTED	$ 0.59	$ 2.65	$ (2.15)	$ 6.01

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, 2009	Nine Months Ended September 30, 2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$(101,067)	$255,179
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	301,622	179,555
Deferred income tax (benefit) expense	(50,785)	147,060
Amortization of debt issuance costs and debt discount	6,916	3,618
Accretion of tax sharing liability	1,227	934
Stock-based compensation	4,047	4,917
Amortization of deferred gain on sale	(12,595)	(7,677)
Gain on sale of properties	(5,709)	-
Undeveloped leasehold and oil and gas property impairments	14,743	9,016
Change in Production Participation Plan liability	3,002	26,964
Unrealized loss on derivative contracts	145,650	7,021
Other non-current	646	(14,744)
Changes in current assets and liabilities:		
Accounts receivable trade	(2,317)	(77,398)
Prepaid expenses and other	30,062	(17,836)
Accounts payable and accrued liabilities	(33,544)	26,683
Accrued interest	10,612	9,982
Other current liabilities	(24,693)	58,178
Net cash provided by operating activities	287,817	611,452
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(31,475)	(413,219)
Drilling and development capital expenditures	(401,227)	(638,400)
Proceeds from sale of oil and gas properties	80,308	1,445
Proceeds from sale of marketable securities	-	764
Net proceeds from sale of 11,677,500 units in Whiting USA Trust I	-	193,824
Net cash used in investing activities	(352,394)	(855,586)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of 6.25% convertible perpetual preferred stock	334,112	-
Issuance of common stock	234,753	-
Preferred stock dividends paid	(4,911)	-
Long-term borrowings under credit agreement	310,000	925,000
Repayments of long-term borrowings under credit agreement	(780,000)	(675,000)
Debt issuance costs	(23,141)	-
Net cash provided by financing activities	70,813	250,000
NET CHANGE IN CASH AND CASH EQUIVALENTS	6,236	5,866
CASH AND CASH EQUIVALENTS:		
Beginning of period	9,624	14,778
End of period	$15,860	$20,644

See notes to consolidated financial statements. (Continued)

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid (refunded) for income taxes	$(2,484)	$1,175
Cash paid for interest	$30,265	$34,227
NONCASH INVESTING ACTIVITIES:		
Accrued capital expenditures during the period	$23,372	$82,840

See notes to consolidated financial statements. (Concluded)

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WHITING PETROLEUM CORPORATION

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

	Preferred Stock		Common Stock		Additional Paid-in	Accumulated Other Comprehensive Income	Retained	Total Stockholders'	Comprehensive Income
	Shares	Amount	Shares	Amount	Capital	(Loss)	Earnings	Equity	(Loss)
BALANCES-January 1, 2008	-	$ -	42,480	$42	$968,876	$(46,116)	$568,024	$1,490,826	
Net income	-	-	-	-	-	-	255,179	255,179	$255,179
Change in derivative fair values, net of taxes of $23,878	-	-	-	-	-	(41,274)	-	(41,274)	(41,274)
Realized loss on settled derivative contracts, net of taxes of $41,379	-	-	-	-	-	71,523	-	71,523	71,523
Total comprehensive income									$285,428
Restricted stock issued	-	-	139	1	-	-	-	1	
Restricted stock forfeited	-	-	(4)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(30)	-	(1,743)	-	-	(1,743)	
Stock-based compensation	-	-	-	-	4,917	-	-	4,917	
BALANCES-September 30, 2008	-	$ -	42,585	$43	$972,050	$(15,867)	$823,203	$1,779,429	
BALANCES-December 31, 2008	-	$ -	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 derivatives, 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 loss									$(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

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. Whiting’s 2008 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 has been no material change to the information disclosed in the notes to the consolidated financial statements included in Whiting’s 2008 Annual Report on Form 10-K. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

Earnings Per Share—Basic net income per common share is calculated by dividing adjusted net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted net income per common share is calculated by dividing adjusted net income 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, and convertible perpetual preferred stock using the if-converted method. 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 accordingly.

Subsequent Events—The Company has evaluated subsequent events through October 29, 2009 and has no material subsequent events to report.

2. ACQUISITIONS AND DIVESTITURES

2009 Acquisitions

There were no significant acquisitions during the first nine months of 2009.

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2009 Participation Agreement

On June 4, 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. Estimated proved reserves of 2.8 MMBOE, as of June 1, 2009, were sold by the Company as a result of this divestiture.

2008 Acquisition

Flat Rock Natural Gas Field—On May 30, 2008, Whiting acquired interests in 31 producing gas wells, development acreage and gas gathering and processing facilities on 22,000 gross (11,500 net) acres in the Flat Rock field in Uintah County, Utah for an aggregate acquisition price of $365.0 million.

This acquisition was recorded using the purchase method of accounting. The table below summarizes the allocation of the $359.4 million adjusted purchase price, based on the acquisition date fair value of the assets acquired and the liabilities assumed (in thousands).

	Flat Rock
Purchase price	$359,380
Allocation of purchase price:	
Proved properties	$251,895
Unproved properties	79,498
Gas gathering and processing facilities	35,736
Liabilities assumed	(7,749)
Total	$359,380

Acquisition Pro Forma—In the Company's consolidated statements of income for the year ended December 31, 2008, Flat Rock's results of operations are included with the Company's results beginning May 31, 2008. The following table, however, reflects the unaudited pro forma results of operations for the nine months ended September 30, 2008, as though the Flat Rock acquisition had occurred on the first day of that period. The pro forma information below includes numerous assumptions and is not necessarily indicative of what historical results would have been or what future results of operations will be.

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	Whiting (As reported)	Pro Forma Flat Rock	Pro Forma Consolidated
Nine months ended September 30, 2008:			
Total revenues	$998,258	$17,761	$1,016,019
Net income	$255,179	$1,144	$256,323
Net income per common share – basic	$6.03	$0.03	$6.06
Net income per common share – diluted	$6.01	$0.03	$6.04

2008 Divestiture

Whiting USA Trust I—On April 30, 2008, the Company completed an initial public offering of units of beneficial interest in Whiting USA Trust I (the "Trust"), selling 11,677,500 Trust units at $20.00 per Trust unit, providing net proceeds of $193.8 million after underwriters' fees, offering expenses, and post-close adjustments. The Company used the net proceeds to repay a portion of the debt outstanding under its credit agreement. The net proceeds from the sale of Trust units to the public resulted in a deferred gain on sale of $100.1 million. Immediately prior to the closing of the offering, Whiting conveyed a term net profits interest in certain of its oil and gas properties to the Trust in exchange for 13,863,889 Trust units. The Company has retained 15.8%, or 2,186,389 Trust units, of the total Trust units issued and outstanding.

The net profits interest entitles the Trust to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate at the time when 9.11 MMBOE have been produced and sold from the underlying properties. This is the equivalent of 8.2 MMBOE in respect of the Trust's right to receive 90% of the net proceeds from such production pursuant to the net profits interest, and these reserve quantities are projected to be produced by December 31, 2021, based on the reserve report for the underlying properties as of December 31, 2008.

3. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2009 and December 31, 2008 (in thousands):

	September 30, 2009	December 31, 2008
Credit Agreement	$ 150,000	$ 620,000
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,243 and $1,541, respectively	218,757	218,459
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $299 and $397, respectively	150,847	151,292
Total debt	$ 769,604	$ 1,239,751

Credit Agreement—As of September 30, 2009, 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 has a borrowing base of $1.1 billion with $947.2 million of available borrowing capacity, which is net of $150.0 million in borrowings and $2.8 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2012, when the agreement expires and all outstanding borrowings are due.

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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. Whiting Oil and Gas may, throughout the term of the credit agreement, borrow, repay and reborrow 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 may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of September 30, 2009, $47.2 million was available for additional letters of credit under the agreement.

Interest accrues at the Company's option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. 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, and are included as a component of interest expense. At September 30, 2009, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.3%.

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 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 EBITDAX ratio (as defined in the credit agreement) for the last four quarters 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 EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 2.75 to 1.0 for quarters ending prior to and on December 31, 2009 and 2.5 to 1.0 for quarters ending March 31, 2010 and thereafter. Except for limited exceptions, which include the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement restricts its ability to make any dividends 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, 2009.

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The obligations of Whiting Oil and Gas under the credit agreement are secured by a first lien on substantially all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation has 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 2014. The estimated fair value of these notes was $245.6 million as of September 30, 2009, based on quoted market prices for these same debt securities.

In April 2005, the Company issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount of $3.3 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.4%. The estimated fair value of these notes was $217.8 million as of September 30, 2009, based on quoted market prices for these same debt securities.

In May 2004, the Company issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount of $1.1 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.3%. The estimated fair value of these notes was $149.3 million as of September 30, 2009, based on quoted market prices for these same debt securities.

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 notes are fully, unconditionally, jointly and severally guaranteed by all of the Company's wholly-owned operating subsidiaries, Whiting Oil and Gas and Whiting Programs, Inc. (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 ("SEC"). Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in guarantor subsidiaries.

Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of $75.0 million of its 7.25% Senior Subordinated Notes due 2012. The interest rate swap was a fixed for floating swap in that the Company received the fixed rate of 7.25% and paid the floating rate. In March 2009, the counterparty exercised its option to cancel the swap contract effective May 1, 2009, resulting in a cancellation fee of $1.4 million paid to the Company.

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 determines 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, 2009 and December 31, 2008 were $10.2 million and $6.5 million, respectively, and were recorded in accrued liabilities. The following table provides a reconciliation of the Company's asset retirement obligations for the nine months ended September 30, 2009 (in thousands):

Asset retirement obligation, January 1, 2009	$54,348	
Additional liability incurred	499	
Revisions in estimated cash flows	20,751	
Accretion expense	5,383	
Obligations on sold properties	(93	)

Liabilities settled	(3,497)
Asset retirement obligation, September 30, 2009	$77,391

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5. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations. The risks managed by using derivative instruments are commodity price risk and interest rate risk.

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 our capital programs and to manage price risks and returns on acquisitions and drilling programs. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not enter into derivative contracts for speculative or trading purposes.

Whiting derivatives—The table below details the Company's costless collar derivatives, including its proportionate share of Trust hedges, entered into to hedge forecasted crude oil and natural gas production revenues, as of October 1, 2009.

	Whiting Petroleum Corporation			
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Oct – Dec 2009	1,467,570	134,622	$61.39 - $76.28	$7.00 - $14.85
Jan – Dec 2010	5,046,289	495,390	$62.34 - $83.00	$6.50 - $15.06
Jan – Dec 2011	4,435,039	436,510	$58.01 - $89.37	$6.50 - $14.62
Jan – Dec 2012	4,065,091	384,002	$57.70 - $91.02	$6.50 - $14.27
Jan – Nov 2013	3,090,000	-	$55.30 - $85.68	n/a
Total	18,103,989	1,450,524		

Derivatives conveyed to Whiting USA Trust I—In connection with the Company's conveyance on April 30, 2008 of a term net profits interest to the Trust and related sale of 11,677,500 Trust units to the public (as further explained in the note on Acquisitions and Divestitures), 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.

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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		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Oct – Dec 2009	33,570	134,622	\$76.00 - \$135.72	\$7.00 - \$14.85
Jan – Dec 2010	126,289	495,390	\$76.00 - \$134.98	\$6.50 - \$15.06
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	379,989	1,450,524		

The 75.8% portion of Trust derivative contracts for 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		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Oct – Dec 2009	105,150	421,668	\$76.00 - \$135.72	\$7.00 - \$14.85
Jan – Dec 2010	395,567	1,551,678	\$76.00 - \$134.98	\$6.50 - \$15.06
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	1,190,217	4,543,380		

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 has 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 balance sheet 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 months ended September 30, 2009, \$7.8 million (\$4.8 million net of tax) of derivative gains relating to de-designated commodity hedges were reclassified from accumulated other comprehensive income into earnings. During the nine months ended September 30, 2009, \$14.6 million (\$9.2 million net of tax) of derivative gains relating to de-designated commodity hedges were reclassified from accumulated other comprehensive income into earnings. As of September 30, 2009, accumulated other comprehensive income amounted to $43.0 million ($27.2 million net of tax), which consisted entirely of unrealized deferred gains on commodity derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of $19.2 million related to de-designated commodity hedges during the next twelve months.

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Interest rate derivative contract—In August 2004, the Company entered into an interest rate swap agreement to manage its exposure to interest rate risk on a portion of its fixed-rate borrowings. The interest rate swap effectively modified the Company's exposure to interest rate risk by converting the fixed rate on $75.0 million of the Company's Senior Subordinated Notes due 2012 to a floating rate. This agreement involved the receipt of fixed rate amounts in exchange for floating rate interest payments over the life of the agreement without an exchange of the underlying notional amount. The interest rate swap was designated as a fair value hedge. In March 2009, the counterparty exercised its option to cancel the swap contract effective May 1, 2009, resulting in a cancellation fee of $1.4 million paid to the Company.

SFAS 161—Effective January 1, 2009, the Company adopted Financial Accounting Standard Board ("FASB") Statement No. 161, Disclosure about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133 ("SFAS 161"), as codified in FASB ASC topic 815, Derivatives and Hedges ("FASB ASC 815"). SFAS 161 expands interim and annual disclosures about derivative and hedging activities that are intended to better convey the purpose of derivative use and the risks managed. The adoption of SFAS 161 did not have an impact on the Company's consolidated financial statements, other than additional disclosures which are set forth below.

All derivative instruments are recorded on the consolidated balance sheet at fair value. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands).

		Fair Value	
Designated as ASC 815 Hedges	Balance Sheet Classification	September 30, 2009	December 31, 2008
Derivative assets			
Commodity contracts	Current derivative assets	$ -	$ 30,198
Commodity contracts	Non-current derivative assets	-	13,163
Interest rate swap contract	Other long-term assets	-	1,690
Total derivative assets		$ -	$ 45,051
Derivative liabilities			
Commodity contracts	Current derivative liabilities	$ -	$ 4,784
Commodity contracts	Non-current derivative liabilities	-	9,224
Total derivative liabilities		$ -	$ 14,008
Not Designated as ASC 815 Hedges			
Derivative assets			
Commodity contracts	Current derivative assets	$ 7,803	$ 16,582
Commodity contracts	Non-current derivative assets	12,778	24,941
Total derivative assets		20,581	41,523
Derivative liabilities			
Commodity contracts	Current derivative liabilities	$ 25,050	$ 12,570

Commodity contracts	Non-current derivative liabilities	86,197	18,907
Total derivative liabilities		$ 111,247	$ 31,477

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Commodity derivative contracts—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, 2009 and 2008 (in thousands).

ASC 815 Cash Flow Hedging Relationships	Location of Gain (Loss) Not Recognized in Income	Gain (Loss) Recognized in OCI (Effective Portion) Nine Months Ended September 30, 2009	2008
Commodity contracts	Other comprehensive income	$ 21,147	$ (65,152)
		Three Months Ended September 30, 2009	2008
Commodity contracts	Other comprehensive income	$ -	$ 61,120

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Nine Months Ended September 30, 2009	2008
Commodity contracts	Gain (loss) on hedging activities	$ 28,072	$ (112,902)
		Three Months Ended September 30, 2009	2008
Commodity contracts	Gain (loss) on hedging activities	$ 7,774	$ (41,879)

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	(Gain) Loss Recognized in Income (Ineffective Portion) Nine Months Ended September 30, 2009	2008
Commodity contracts	Commodity derivative (gain) loss, net	$ 22,655	$ -
		Three Months Ended September 30, 2009	2008
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, 2009	2008
Commodity contracts	Commodity derivative (gain) loss, net	$ 149,251	$ 7,064

		Three Months Ended September 30, 2009	2008
Commodity contracts	Commodity derivative (gain) loss, net	$ (10,391)	$ (10,561)

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Fair value hedge—In March 2009, the Company's derivative counterparty exercised its option to cancel the Company's interest rate swap contract effective May 1, 2009. Prior to the cancellation, the gain or loss on the hedged item ($75.0 million of fixed-rate borrowings under the Company's Senior Subordinated Notes due 2012) attributable to the hedged benchmark interest rate risk (risk of changes in the LIBOR swap rate) and the offsetting gain or loss on the related interest rate swap for the three and nine months ended September 30, 2009 and 2008 were as follows (in thousands):

	Gain (Loss) on Swap		Gain (Loss) on Borrowing	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
Income Statement Classification	2009	2008	2009	2008
Interest expense	$(330)	$(115)	$330	$115
	Three Months Ended September 30,		Three Months Ended September 30,	
	2009	2008	2009	2008
Interest expense	$-	$10	$-	$(10)

There was no difference, or therefore ineffectiveness, between the gain (loss) on swap and gain (loss) on borrowing amounts in the above table because this swap met the criteria to qualify for the "short cut" method of assessing effectiveness. Accordingly, the change in fair value of the debt was assumed to equal the change in the fair value of the interest rate swap. In addition, the net swap settlements that accrued each period were also reported in interest expense.

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 the counterparty to secure contract performance obligations.

6. FAIR VALUE MEASUREMENTS

The Company follows the Fair Value Measurement and Disclosure topic of the FASB ASC, 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.

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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 following table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2009, 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, 2009
Financial Assets				
Commodity derivatives - current	$ -	$ 7,803	$ -	$ 7,803
Commodity derivatives - non-current	-	12,778	-	12,778
Total financial assets	$ -	$ 20,581	$ -	$ 20,581
Financial Liabilities				
Commodity derivatives - current	$ -	$ 25,050	$ -	$ 25,050
Commodity derivatives - non-current	-	86,197	-	86,197
Total financial liabilities	$ -	$ 111,247	$ -	$ 111,247

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 modeling techniques that consider the 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 rate used in the fair values of these instruments includes a measure of nonperformance risk. The Company utilizes the counterparties' valuations to assess the reasonableness of its own valuations.

7. DEFERRED COMPENSATION

Production Participation Plan—The Company has a Production Participation Plan (the "Plan") in which all employees participate. On an annual basis, interests in oil and gas properties acquired, developed or sold during the year are allocated to the Plan as determined annually by the Compensation Committee. 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, 2009 and 2008 amounted to $10.4 million and $30.0 million, respectively, charged to general and administrative expense and $1.5 million and $4.7 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, 2009, the Company used three-year average historical NYMEX prices of $78.04 for crude oil and $6.95 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control (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 prices at September 30, 2009, 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 $120.5 million. This amount includes $19.1 million attributable to proved undeveloped oil and gas properties and $11.9 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2010. 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 for the nine months ended September 30, 2009 (in thousands):

Production Participation Plan liability, January 1, 2009	$66,166
Change in liability for accretion, vesting and changes in estimates	14,903
Reduction in liability for cash payments accrued and recognized as compensation expense	(11,901)
Production Participation Plan liability, September 30, 2009	$69,168

8. STOCKHOLDERS' EQUITY

6.25% Convertible Perpetual Preferred Stock Offering—In June 2009, the Company completed a public offering of 6.25% convertible perpetual 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 convertible perpetual 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. Whiting paid the first dividend of $4.9 million on September 15, 2009. Each share of convertible perpetual 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 convertible perpetual 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 certain conditions are met. The holders of convertible preferred stock have no voting rights unless dividends payable on the convertible preferred stock are in arrears for six or more quarterly periods.

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.

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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, 2009 and 2008 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 acquired, additional information is obtained or as the tax environment changes.

10. NET INCOME PER SHARE

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

	Three Months Ended September 30, 2009			Three Months Ended September 30, 2008		
	Income	Weighted Avg Shares Outstanding	Per Share Amount	Income	Weighted Avg Shares Outstanding	Per Share Amount
Net income	$ 35,855			$ 112,417		
Less:						
Preferred stock dividends declared	(4,911)			-		
Preferred stock dividends accumulated	(886)			-		
Basic:						
Adjusted net income available to common stockholders	$ 30,058	50,845	$ 0.59	$ 112,417	42,322	$ 2.66
Effect of dilutive securities						
Restricted stock and stock options	-	329		-	143	
Diluted:						
Adjusted net income available to common stockholders plus assumed conversions	$ 30,058	51,174	$ 0.59	$ 112,417	42,465	$ 2.65

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For the three months ended September 30, 2009, the diluted earnings per share calculation excludes the effect of 7,946,324 common shares issuable upon the assumed conversion of the 6.25% perpetual preferred stock because their effect was anti-dilutive.

	Nine Months Ended September 30, 2009			Nine Months Ended September 30, 2008		
	Income	Weighted Avg Shares Outstanding	Per Share Amount	Income	Weighted Avg Shares Outstanding	Per Share Amount
Net income (loss)	$ (101,067)			$ 255,179		
Less:						
Preferred stock dividends declared	(4,911)			-		
Preferred stock dividends accumulated	(886)			-		
Basic:						
Adjusted net income available to common stockholders	$ (106,864)	49,774	$ (2.15)	$ 255,179	42,305	$ 6.03
Effect of dilutive securities						
Restricted stock and stock options	-	-		-	159	
Diluted:						
Adjusted net income available to common stockholders plus assumed conversions	$ (106,864)	49,774	$ (2.15)	$ 255,179	42,464	$ 6.01

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 because their effect was anti-dilutive, as well as 2,881,634 weighted average common shares issuable upon the assumed conversion of the 6.25% perpetual preferred stock.

11. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. The Company is currently assessing the impact that the adoption will have on our disclosures, operating results, statement of financial position and statement of cash flows.

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In June 2009, the FASB issued SFAS No. 168, The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles, as codified in FASB ASC topic Generally Accepted Accounting Principles, a replacement of FASB Statement No. 162. This standard establishes only two levels of GAAP, authoritative and nonauthoritative. The FASB ASC was not intended to change or alter existing GAAP, and the Company's adoption effective July 1, 2009 did not therefore have any impact on its consolidated financial statements other than to modify certain existing disclosures. The FASB ASC will become the source of authoritative, nongovernmental GAAP, except for rules and interpretive releases of the SEC, which are sources of authoritative GAAP for SEC registrants. All other nongrandfathered, non-SEC accounting literature not included in the FASB ASC will become nonauthoritative. FASB ASC is effective for financial statements for interim or annual reporting periods ending after September 15, 2009. Upon adoption the Company began to use the new guidelines and numbering system prescribed by the FASB ASC when referring to GAAP in the third quarter of fiscal 2009.

In May 2009, the FASB issued SFAS No. 165, Subsequent Events ("SFAS 165"), as codified in FASB ASC topic Subsequent Events. This standard is intended to establish general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Specifically, this standard sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. SFAS 165 is effective for fiscal years and interim periods ended after June 15, 2009. The Company adopted SFAS 165 effective April 1, 2009, which did not have an impact on its consolidated financial statements, other than additional disclosures.

In April 2009, the FASB issued two FASB Staff Positions ("FSP") intended to provide additional application guidance and enhanced disclosures regarding fair value measurements and impairments of securities. FSP No. FAS 157-4, Determining Fair Value When the Volume or Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, as codified in FASB ASC topic Fair Value Measurement and Disclosure, provides additional guidelines for estimating fair value in accordance with FASB SFAS No. 157, Fair Value Measurements ("SFAS 157"). FSP No. 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, increases the frequency of fair value disclosures. These FSPs are effective for fiscal years and interim periods ended after June 15, 2009. The Company adopted these FSPs effective April 1, 2009, which did not have an impact on its consolidated financial statements, other than additional disclosures.

The Company elected to implement SFAS 157 with the one-year deferral permitted by FSP No. FAS 157-2, Effective Date of FASB Statement No. 157 ("FSP 157-2"), issued February 2008 and codified in FASB ASC topic Fair Value Measurement and Disclosure. FSP 157-2 deferred the effective date of SFAS 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value. Accordingly, the Company adopted SFAS 157 on January 1, 2009 for its nonfinancial assets and nonfinancial liabilities measured at fair value on a non-recurring basis. This deferred adoption of SFAS 157, however, did not have an impact on the Company's consolidated financial statements nor its disclosures. As it relates to the Company, this delayed adoption applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; impaired oil and gas property assessments; and the initial recognition of asset retirement obligations for which fair value is used.

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In December 2007, the FASB issued SFAS No. 141(R), Business Combinations (“SFAS 141(R)”), which replaces SFAS No. 141, as codified in FASB ASC topic Business Combinations. SFAS 141(R) is effective for business combinations with acquisition dates on or after fiscal years beginning after December 15, 2008, and the Company adopted SFAS 141(R) effective January 1, 2009. As the Company has not entered into any business combinations during the first nine months of 2009, the adoption of SFAS 141(R) has not had any impact on the Company’s consolidated financial statements. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. SFAS 141(R) also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination.

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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 oil and gas 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.

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Oil and natural gas prices have fallen significantly since their third quarter 2008 levels. For example, the daily average NYMEX oil price was $118.13 per Bbl for the third quarter of 2008, $58.75 per Bbl for the fourth quarter of 2008, and $57.13 per Bbl for the first nine months of 2009. Similarly, daily average NYMEX natural gas prices have declined from $10.27 per Mcf for the third quarter of 2008 to $6.96 per Mcf for the fourth quarter of 2008 and $3.93 for the first nine months of 2009. 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, on a non-cash basis.

2009 Highlights and Future Considerations

6.25% Convertible Perpetual Preferred Stock Offering. In June 2009, we completed a public offering of 6.25% convertible perpetual 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. We used the net proceeds to repay a portion of the debt outstanding under our credit agreement.

Each holder of the convertible perpetual 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 dividends are declared by our board of directors. We paid the first dividend of $4.9 million on September 15, 2009. Each share of convertible perpetual 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 our common stock based on an initial conversion price of $43.4163, subject to adjustment upon the occurrence of certain events. The convertible perpetual preferred stock is not redeemable by us. At any time on or after June 15, 2013, we may cause all outstanding shares of convertible preferred stock to be automatically converted into shares of common stock if certain conditions are met. The holders of convertible preferred stock have no voting rights unless dividends payable on the convertible preferred stock are in arrears for six or more quarterly periods.

Sanish Field Transaction. On June 4, 2009, we 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 our net working interest drilling and well completion costs to receive 50% of our working interest and net revenue interest in the first and second wells planned for each of the units. Pursuant to the agreement, we will remain the operator for each unit.

At the closing of the agreement, the private company paid us $107.3 million, representing $6.4 million for acreage costs, $65.8 million for 65% of our cost in 18 wells drilled or drilling and $35.1 million for a 50% interest in our Robinson Lake gas plant and oil and gas gathering system. We used the proceeds to repay a portion of the debt outstanding under our credit agreement. We sold estimated proved reserves of 2.8 MMBOE as of June 1, 2009, as a result of this transaction.

Common Stock Offering. In February 2009, we completed a public offering of our 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. We used the net proceeds to repay a portion of the debt outstanding under our credit agreement.

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Operational Highlights. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken formation. Net production in the Sanish field increased 80% from a net 5.9 MBOE/d in September 2008 to a net 10.6 MBOE/d in September 2009. Net production in the Parshall field increased 4% from a net 6.6 MBOE/d in September 2008 to a net 6.8 MBOE/d in September 2009.

We continue to have significant development and related infrastructure activity on the Postle and North Ward Estes fields acquired in 2005, which have resulted in reserve and production increases. Our expansion of the CO_2 flood at both fields continues to generate positive results. During the first nine months of 2009, we incurred $122.5 million of development expenditures on these two projects.

The Postle field is located in Texas County, Oklahoma. Four of our five producing units are currently under active CO_2 enhanced recovery projects. As of October 16, 2009, we were injecting 140 MMcf/d of CO_2 in this field. Production from the field has increased 32% from a net 6.8 MBOE/d in September 2008 to a net 9.0 MBOE/d in September 2009.

The North Ward Estes field is located in Ward and Winkler Counties, Texas and is responding positively to our water and CO_2 floods, which we initiated in Phase I during May 2007. In early March 2009, we began CO_2 injection in Phase II of the project. As of October 16, 2009, we were injecting 199 MMcf/d of CO_2 in this field. Production from the field remained consistent at a net 6.6 MBOE/d from September 2008 to September 2009. In this field, we are developing new and reactivated wells for water and CO_2 injection and production purposes. Additionally, we plan to install oil, gas and water processing facilities in four phases through 2015, and we estimate that the first three phases will be substantially complete by December 2009.

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Results of Operations

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Selected Operating Data:	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net production:		
Oil (MMBbls)	11.3	8.7
Natural gas (Bcf)	22.6	22.4
Total production (MMBOE)	15.1	12.4
Net sales (in millions):		
Oil (1)	$539.6	$904.1
Natural gas (1)	77.0	198.6
Total oil and natural gas sales	$616.6	$1,102.7
Average sales prices:		
Oil (per Bbl)	$47.79	$104.21
Effect of oil hedges on average price (per Bbl)	0.07	(13.01)
Oil net of hedging (per Bbl)	$47.86	$91.20
Average NYMEX price	$57.13	$113.38
Natural gas (per Mcf)	$3.41	$8.87
Effect of natural gas hedges on average price (per Mcf)	0.05	-
Natural gas net of hedging (per Mcf)	$3.46	$8.87
Average NYMEX price	$3.93	$9.75
Cost and expense (per BOE):		
Lease operating expenses	$11.78	$14.33
Production taxes	$2.87	$5.80
Depreciation, depletion and amortization expense	$20.04	$14.47
General and administrative expenses	$2.03	$4.18

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $486.1 million to $616.6 million in the first nine months of 2009 compared to the same period in 2008. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 30% between periods, while our natural gas sales volumes increased 1%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production at our two large CO2 projects, Postle and North Ward Estes. Oil production from the Bakken area increased 2,300 MBbl compared to the first nine months of 2008, while Postle oil production increased 490 MBbl and North Ward Estes oil production increased 330 MBbl over the same prior year period. These production increases were partially offset by the Whiting USA Trust I (the "Trust") divestiture, which decreased oil production by 205 MBbl, as well as normal field production decline. The gas volume increase between periods was primarily the result of incremental gas production of 1,450 MMcf from the Flat Rock acquisition, which we completed on May 30, 2008, and higher production volumes of 1,300 MMcf, 1,150 MMcf and 990 MMcf due to well completions in the Boies Ranch area, North Dakota Bakken area and Gulf Coast region, respectively. These production increases were partially offset by the Trust divestiture, which decreased gas production by 1,035 MMcf, as well as normal field production decline. Offsetting the production increases were declines in average sales prices. Our average price for oil before the effects of hedging decreased 54% between periods, and our average price for natural gas before the effects of hedging decreased 62%.

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Gain (Loss) on Hedging Activities. Realized cash settlements on commodity derivatives that we have designated as cash flow hedges are recognized as gain (loss) on hedging activities. During the first nine months of 2009, we incurred cash settlement gains of $13.4 million on such crude oil hedges. During the first nine months of 2008, we incurred realized cash settlement losses of $112.9 million on crude oil derivatives designated as cash flow hedges. None of our natural gas derivatives were designated as cash flow hedges during the first nine months of 2009 or 2008. 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 a result, we reclassified from accumulated other comprehensive income into earnings $14.6 million in unrealized non-cash gains upon the expiration of these de-designated crude oil hedges from April 1 to September 30, 2009. See Item 3, “Qualitative and Quantitative Disclosures About Market Risk” for a list of our outstanding oil and natural gas derivatives as of October 1, 2009.

Amortization of Deferred Gain on Sale. In connection with the sale of 11,677,500 Trust units to the public and related oil and gas property conveyance on April 30, 2008, we recognized a deferred gain on sale of $100.1 million. This deferred gain is amortized to income over the life of the Trust on a units-of-production basis. For the nine months ended September 30, 2009 and 2008, we recognized $12.6 million and $7.7 million, respectively, in income as amortization of deferred gain on sale.

Gain on Sale of Properties. During the nine months ended September 30, 2009, we entered into a participation agreement with a privately held independent oil company covering acreage located primarily in the western portion of the Sanish field in Mountrail County, North Dakota. At the closing of the agreement, the private company paid us $107.3 million, resulting in a pre-tax gain on sale of $4.6 million. In addition, we sold our interest in several non-core properties for an aggregate amount of $1.3 million in cash and recognized a pre-tax gain on sale of $1.1 million. There was no gain or loss on the sale of properties during the nine months ended September 30, 2008.

Lease Operating Expenses. Our lease operating expenses during the first nine months of 2009 were $177.3 million, a $0.5 million decrease over the same period in 2008. Our lease operating expenses per BOE decreased from $14.33 during the first nine months of 2008 to $11.78 during the first nine months of 2009. The decrease of 18% on a BOE basis was primarily caused by increased production and a decrease of $11.3 million in electric power and fuel costs during the first nine months of 2009 as compared to the same period in 2008, partially offset by a high level of workover activity. Workovers amounted to $37.8 million in the first nine months of 2009, as compared to $17.8 million in the same period of 2008. The increase in workover activity primarily relates to our two CO2 projects, which are evolving past the construction and start-up phases and moving into an ongoing maintenance and repair phase that involves a significantly higher number of producing wells and injection wells.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes during the first nine months of 2009 were $43.2 million, a $28.8 million decrease over the same period in 2008, primarily due to lower oil and natural gas sales. For the first nine months of 2009 and 2008, our production taxes were 7.0% and 6.5%, respectively, of oil and natural gas sales. Our production tax rate for the first nine months of 2009 was greater than the rate for same period in 2008 mainly due to successful wells that were completed in the North Dakota Bakken area during the latter half of 2008 and first nine months of 2009 and that carry an 11.5% production tax rate.

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Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $122.1 million as compared to the first nine months of 2008. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2009	2008
Depletion	$293,869	$174,715
Depreciation	2,370	2,499
Accretion of asset retirement obligations	5,383	2,341
Total	$301,622	$179,555

DD&A increased $122.1 million primarily due to $119.2 million in higher depletion expense between periods. Of this $119.2 million increase in depletion, $37.2 million related to higher oil and gas volumes produced during the first nine months of 2009, while $82.0 million related to our higher depletion rate in 2009. On a BOE basis, our DD&A rate increased by 38% from $14.47 for the first nine months of 2008 to $20.04 for the first nine months of 2009. The primary factors causing this rate increase were (i) $595.5 million in drilling expenditures incurred during the past twelve months, (ii) net oil and natural gas reserve reductions of 11.6 MMBOE during 2008, which were primarily attributable to a 39.0 MMBOE downward revision for lower oil and natural gas prices at December 31, 2008, and (iii) 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 increased $9.0 million, as compared to the first nine months of 2008. The components of exploration and impairment costs were as follows (in thousands):

	Nine Months Ended September 30,	
	2009	2008
Exploration	$24,785	$21,550
Impairment	14,743	9,016
Total	$39,528	$30,566

Exploration costs increased $3.2 million during the first nine months of 2009 as compared to the same period in 2008 primarily due to rig termination fees recognized during 2009, partially offset by decreased accrued Production Participation Plan payments for geological and geophysical ("G&G") personnel. Rig termination fees totaled $6.5 million during the first nine months of 2009, while we did not pay any rig termination fees in the first nine months of 2008. Accrued Production Participation Plan distributions for exploration personnel were $3.2 million lower during the first nine months of 2009 as compared to the same prior year period primarily due to decreased net oil and gas sales. During the first nine months of 2009, we drilled one exploratory dry hole in the Rocky Mountain region totaling $2.3 million, while during the same period in 2008 we drilled one exploratory dry hole in the Permian region totaling $1.5 million. The impairment charges in the first nine months of 2009 and 2008 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of September 30, 2009, the amount of unproved properties being amortized totaled $81.6 million, as compared to $72.2 million as of September 30, 2008. Also lending to the increase in impairment expense during the 2009 period was $3.1 million in non-cash impairment charges for the partial write-down of certain proved properties whose net book values exceeded their undiscounted future cash flows.

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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,	
	2009	2008
General and administrative expenses	$68,100	$82,411
Reimbursements and allocations	(37,524)	(30,508)
General and administrative expense, net	$30,576	$51,903

General and administrative expense before reimbursements and allocations decreased $14.3 million to $68.1 million during the first nine months of 2009. The largest component of the decrease related to $22.8 million in lower accrued distributions under our Production Participation Plan ("Plan") between periods due to (i) a lower level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) resulting from lower oil and natural gas prices during the first nine months of 2009 as compared to the same period of 2008, and (ii) the Trust divestiture completed in April 2008 which increased 2008 accrued distributions under the Plan. These lower accrued Plan distributions were partially offset by $4.8 million in additional employee compensation for personnel hired during the past twelve months as well as general pay increases. The increase in reimbursements and allocations in 2009 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expense, net as a percentage of oil and natural gas sales remained constant at 5% for the first nine months of 2009 and 2008.

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

	Nine Months Ended September 30,	
	2009	2008
Senior Subordinated Notes	$32,826	$32,698
Credit Agreement	10,589	13,410
Amortization of debt issue costs and debt discount	6,916	3,618
Other	1,366	1,090
Capitalized interest	(2,677)	(2,056)
Total	$49,020	$48,760

The increase in interest expense of $0.3 million between periods was mainly due to higher debt issue cost amortization associated with additional issuance costs incurred in April 2009 when renewing our credit agreement. This increase in interest expense was partially offset by lower effective interest rates on our credit agreement. Our weighted average effective cash interest rate was 5.4% during the first nine months of 2009 compared to 6.2% during the first nine months of 2008. Our weighted average debt outstanding during the first nine months of 2009 was $1,080.8 million versus $1,002.6 million for the first nine months of 2008. After inclusion of non-cash interest costs for the amortization of debt issue costs, debt discounts and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 6.2% during the first nine months of 2009 compared to 6.6% during the first nine months of 2008.

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Change in Production Participation Plan Liability. For the nine months ended September 30, 2009, this non-cash expense was $3.0 million, a decrease of $24.0 million as compared to the same period in 2008. This expense represents the change in the vested present value of estimated future payments to be made after 2010 to participants under our Plan. Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan's five-year vesting period. This expense in 2009 and 2008 primarily reflected (i) changes to future cash flow estimates stemming from the volatile commodity price environment during the first nine months of each respective year, (ii) recent drilling activity and property acquisitions, and (iii) employees' continued vesting in the Plan. The average NYMEX prices used to estimate this liability decreased by $1.40 for crude oil and $0.69 for natural gas for the nine months ended September 30, 2009, as compared to increases of $20.95 for crude oil and $0.71 for natural gas over the same period in 2008. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

Commodity Derivative (Gain) Loss, Net. During 2008, we entered into certain 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 as of March 31, 2009 and have elected to discontinue 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. The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Nine Months Ended September 30,	
	2009	2008
Change in unrealized losses on derivative contracts	$137,616	$7,021
Realized cash settlement losses	11,635	43
Loss on hedging ineffectiveness	22,655	-
Total	$171,906	$7,064

The increase of $130.6 million in unrealized losses on derivative contracts during the first nine months of 2009 as compared to the same prior year period was due to the fact that (i) we averaged 20.5 MMBbls of crude oil hedged during the nine months ended September 30, 2009, while we only averaged 2.7 MMBbls of crude oil hedged during the nine months ended September 30, 2008, and (ii) there was a more significant upward shift in the forward price curve for NYMEX crude oil during the nine months ended September 30, 2009 as compared to the upward shift in the same price curve during the nine months ended September 30, 2008.

Income Tax Expense (Benefit). Income tax benefit totaled $51.8 million for the first nine months of 2009, versus $148.4 million of income tax expense for the first nine months of 2008. Our effective income tax rate decreased from 36.8% for the first nine months of 2008 to 33.9% for the first nine months of 2009. Our pre-tax book loss when taken together with our permanent items resulted in a decrease in our overall effective tax rate. This decrease, however, was partially offset by an increase in our effective tax rate caused by a change in our drilling activity in various states.

Net Income (Loss) Available to Common Shareholders. Net income (loss) available to common shareholders decreased from $255.2 million in income during the first nine months of 2008 to a $106.0 million loss during the first nine months of 2009. The primary reasons for this decrease include a 48% decrease in oil prices (net of hedging); a 61% decrease in natural gas prices (net of hedging); higher unrealized commodity derivative losses, DD&A, exploration and impairment, interest expense and dividends paid on preferred stock. These negative factors were partially offset by a 21% increase in equivalent volumes sold; lower lease operating expenses, production taxes, general and administrative expenses, Production Participation Plan expense and income taxes; and higher amortization of deferred gain on sale, as well as the gain on sale of properties during the first nine months of 2009.

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Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008

Selected Operating Data:	Three Months Ended September 30, 2009	2008
Net production:		
Oil (MMBbls)	3.9	3.3
Natural gas (Bcf)	7.1	8.2
Total production (MMBOE)	5.1	4.6
Net sales (in millions):		
Oil (1)	$232.3	$354.8
Natural gas (1)	23.8	70.6
Total oil and natural gas sales	$256.1	$425.4
Average sales prices:		
Oil (per Bbl)	$58.86	$108.04
Effect of oil hedges on average price (per Bbl)	(2.42)	(12.76)
Oil net of hedging (per Bbl)	$56.44	$95.28
Average NYMEX price	$68.29	$118.13
Natural gas (per Mcf)	$3.35	$8.65
Effect of natural gas hedges on average price (per Mcf)	0.05	-
Natural gas net of hedging (per Mcf)	$3.40	$8.65
Average NYMEX price	$3.40	$10.27
Cost and expense (per BOE):		
Lease operating expenses	$11.46	$13.93
Production taxes	$3.66	$6.08
Depreciation, depletion and amortization expense	$19.74	$15.99
General and administrative expenses	$2.21	$3.72

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $169.3 million to $256.1 million in the third quarter of 2009 compared to the same period in 2008. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 20% between periods, while our natural gas sales volumes decreased 13%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production at our two large CO2 projects, Postle and North Ward Estes. Oil production from the Bakken increased 480 MBbl compared to the third quarter of 2008, while Postle oil production increased 195 MBbl and North Ward Estes oil production increased 95 MBbl over the same prior year period. These production increases were partially offset by normal field production decline. The gas volume decrease between periods was primarily the result of normal field production decline across all of our regions. These production decreases were partially offset by higher production volumes in the North Dakota Bakken area of 495 MMcf due to new wells drilled. Offsetting the overall production increases were lower average sales prices. Our average price for oil before the effects of hedging decreased 46% between periods, and our average price for natural gas before the effects of hedging decreased 61%.

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Gain (Loss) on Hedging Activities. Realized cash settlements on commodity derivatives that we have designated as cash flow hedges are recognized as gain (loss) 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 as of March 31, 2009 and have elected to discontinue hedge accounting prospectively. As a result, we reclassified from accumulated other comprehensive income into earnings $7.8 million in unrealized non-cash gains upon the expiration of these de-designated crude oil hedges during the third quarter of 2009. None of our oil derivatives were designated as cash flow hedges during the third quarter of 2009. During the third quarter of 2008, we incurred realized cash settlement losses of $41.9 million on crude oil derivatives designated as cash flow hedges. None of our natural gas derivatives were designated as cash flow hedges during the third quarter of 2009 or 2008. See Item 3, “Qualitative and Quantitative Disclosures About Market Risk” for a list of our outstanding oil and natural gas derivatives as of October 1, 2009.

Amortization of Deferred Gain on Sale. In connection with the sale of 11,677,500 Trust units to the public and related oil and gas property conveyance on April 30, 2008, we recognized a deferred gain on sale of $100.1 million. This deferred gain is amortized to income over the life of the Trust on a units-of-production basis. For the three months ended September 30, 2009 and 2008, we recognized $4.2 million and $4.7 million, respectively, in income as amortization of deferred gain on sale.

Gain on Sale of Properties. During the three months ended September 30, 2009, we sold our interest in several non-core properties for an aggregate amount of $0.7 million in cash and recognized a pre-tax gain on sale of $1.1 million. There was no gain or loss on the sale of properties during the three months ended September 30, 2008.

Lease Operating Expenses. Our lease operating expenses during the third quarter of 2009 were $58.8 million, a $5.9 million decrease over the same period in 2008. Our lease operating expenses per BOE decreased from $13.93 during the third quarter of 2008 to $11.46 during the third quarter of 2009. The decrease of 18% on a BOE basis was primarily caused by increased production and decreased electric power and fuel costs of $5.0 million during the third quarter of 2009 as compared to the same period in 2008, partially offset by a high level of workover activity. Workovers amounted to $11.6 million in the third quarter of 2009, as compared to $9.4 million in the third quarter of 2008. The increase in workover activity primarily relates to our two CO_2 projects, which are evolving past the construction and start-up phases and moving into an ongoing maintenance and repair phase that involves a significantly higher number of producing wells and injection wells.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes during the third quarter of 2009 were $18.8 million, a $9.5 million decrease over the same period in 2008, primarily due to lower oil and natural gas sales. For the third quarter of 2009 and 2008, our production taxes were 7.3% and 6.6%, respectively, of oil and natural gas sales. Our production tax rate for the third quarter of 2009 was greater than the rate for same period in 2008 mainly due to successful wells that were completed in the North Dakota Bakken area during the latter half of 2008 and first nine months of 2009 and that carry an 11.5% production tax rate.

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Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $27.0 million as compared to the third quarter of 2008. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008
Depletion	$98,876	$72,464
Depreciation	771	905
Accretion of asset retirement obligations	1,626	864
Total	$101,273	$74,233

DD&A increased $27.0 million primarily due to $26.4 million in higher depletion expense between periods. Of this $26.4 million increase in depletion, $7.6 million related to higher oil and gas volumes produced during the third quarter of 2009, while $18.8 million related to our higher depletion rate in 2009. On a BOE basis, our DD&A rate increased by 23% from $15.99 for the third quarter of 2008 to $19.74 for the third quarter of 2009. The primary factors causing this rate increase were (i) $595.5 million in drilling expenditures incurred during the past twelve months, (ii) net oil and natural gas reserve reductions of 11.6 MMBOE during 2008, which were primarily attributable to a 39.0 MMBOE downward revision for lower oil and natural gas prices at December 31, 2008, and (iii) 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 increased $1.5 million, as compared to the third quarter of 2008. The components of exploration and impairment costs were as follows (in thousands):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008
Exploration	$5,973	$7,323
Impairment	6,449	3,616
Total	$12,422	$10,939

Exploration costs decreased $1.4 million during the third quarter of 2009 as compared to the same period in 2008 primarily due to a decrease in accrued Production Participation Plan payments for exploration personnel, partially offset by an increase in exploratory dry hole costs. Accrued Production Participation Plan distributions for exploration personnel were $0.7 million lower during the third quarter of 2009 as compared to the same prior year period. During the third quarter of 2009, we drilled one exploratory dry hole in the Rocky Mountain region totaling $2.3 million, while during the same period in 2008 we drilled one exploratory dry hole in the Permian region totaling $1.5 million. The impairment charges in the third quarter of 2009 and 2008 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of September 30, 2009, the amount of unproved properties being amortized totaled $81.6 million, as compared to $72.2 million as of September 30, 2008. Also lending to the increase in impairment expense during the 2009 period was $2.3 million in non-cash impairment charges for the partial write-down of certain proved properties whose net book values exceeded their undiscounted future cash flows.

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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):

	Three Months Ended September 30,	
	2009	2008
General and administrative expenses	$24,417	$28,096
Reimbursements and allocations	(13,103)	(10,815)
General and administrative expense, net	$11,314	$17,281

General and administrative expense before reimbursements and allocations decreased $3.7 million to $24.4 million during the third quarter of 2009. The largest component of the decrease related to $5.5 million in lower accrued distributions under our Production Participation Plan ("Plan") between periods due to a lower level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) resulting from lower oil and natural gas prices during the third quarter of 2009 as compared to the same period of 2008. These lower accrued Plan distributions were partially offset by $1.2 million in additional employee compensation for personnel hired during the past twelve months as well as general pay increases. The increase in reimbursements and allocations in 2009 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expense, net as a percentage of oil and natural gas sales remained constant at 4% for the third quarter of 2009 and 2008.

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

	Three Months Ended September 30,	
	2009	2008
Senior Subordinated Notes	$11,081	$10,755
Credit Agreement	2,436	5,757
Amortization of debt issue costs and debt discount	2,561	1,195
Other	433	358
Capitalized interest	(864)	(522)
Total	$15,647	$17,543

The decrease in interest expense of $1.9 million between periods was mainly due to a lower level of debt outstanding and lower interest rates on borrowings under our credit agreement during the third quarter of 2009, partially offset by an increase in debt issue cost amortization associated with additional issuance costs incurred in April 2009 when renewing our credit agreement. Due to lower borrowings outstanding under our credit agreement during the third quarter 2009, our weighted average effective cash interest rate was 6.6% compared to 5.8% during the third quarter of 2008. Our weighted average debt outstanding during the third quarter of 2009 was $824.9 million versus $1,147.6 million for the third quarter of 2008. After inclusion of non-cash interest costs for the amortization of debt issue costs, debt discounts and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 7.8% during the third quarter of 2009 compared to 6.2% during the third quarter of 2008.

Change in Production Participation Plan Liability. For the three months ended September 30, 2009, the Production Participation Plan liability decreased $0.7 million, while the liability increased $9.1 million in the same period in 2008. This expense represents the change in the vested present value of estimated future payments to be made after 2010 to participants under our Plan. Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan's five-year vesting period. This expense in 2009 and 2008 primarily reflected (i) changes to future cash flow estimates stemming from the volatile commodity price environment during the third quarter of each respective year, (ii) recent drilling activity and property acquisitions, and (iii) employees' continued vesting in the Plan. The average NYMEX prices used to estimate this liability decreased by $0.59 for crude oil and $0.22 for natural gas for the three months ended September 30, 2009, as compared to increases of $5.44 for crude oil and $0.03 for natural gas over the same period in 2008. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

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Commodity Derivative (Gain) Loss, Net. During 2008, we entered into certain 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 as of March 31, 2009 and have elected to discontinue 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. The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Three Months Ended September 30,	
	2009	2008
Change in unrealized (gains) losses on derivative contracts	$(19,567)	$(10,604)
Realized cash settlement losses	9,176	43
Total	$(10,391)	$(10,561)

The increase of $9.0 million in unrealized gains on derivative contracts during the third quarter of 2009 as compared to the same prior year period was due to the fact that (i) we averaged 18.9 MMBbls of crude oil hedged during the three months ended September 30, 2009, while we only averaged 2.0 MMBbls of crude oil hedged during the three months September 30, 2008, and (ii) there was a larger downward shift in the forward price curve for NYMEX crude oil during the three months ended September 30, 2009 as compared to the downward shift in the same price curve during the third quarter of 2008.

Income Tax Expense (Benefit). Income tax expense totaled $26.3 million for the third quarter of 2009, versus $64.5 million for the third quarter of 2008. Our effective income tax rate increased from 36.5% for the third quarter of 2008 to 42.3% for the third quarter of 2009. Losses in the first two quarters and increased earnings in the third quarter resulted in an increase in our effective tax rate in the third quarter of 2009. In addition, a change in our drilling activity in various states resulted in an increase in our effective income tax rate in the third quarter of 2009.

Net Income (Loss) Available to Common Shareholders. Net income available to common shareholders decreased from $112.4 million during the third quarter of 2008 to $30.9 million during the third quarter of 2009. The primary reasons for this decrease include a 41% decrease in oil prices (net of hedging); a 61% decrease in natural gas prices (net of hedging); higher DD&A, exploration and impairment and dividends paid on preferred stock; lower commodity derivative gains; and lower unrealized amortization of deferred gain on sale. These negative factors were partially offset by a 10% increase in equivalent volumes sold; lower lease operating expenses, production taxes, general and administrative expenses, interest expense, Production Participation Plan expense and income taxes; and the gain on sale of properties during the third quarter of 2009.

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Liquidity and Capital Resources

Overview. At September 30, 2009, our debt to total capitalization ratio was 25.2%, we had $15.9 million of cash on hand and $2,284.4 million of stockholders' equity. At December 31, 2008, our debt to total capitalization ratio was 40.7%, we had $9.6 million of cash on hand and $1,808.8 million of stockholders' equity. In the first nine months of 2009, we generated $287.8 million of cash provided by operating activities, a decrease of $323.6 million over the same period in 2008. Cash provided by operating activities decreased primarily due to lower average sales prices for both crude oil and natural gas, partially offset by higher oil and gas volumes produced in the first nine months of 2009 as well as realized cash settlement gains on hedging activities during 2009 rather than the significant cash settlement losses on hedging activities that were incurred during the first nine months of 2008. We also generated $70.8 million from financing activities consisting of $334.1 million in net proceeds received from the issuance of our preferred stock and $234.8 million in net proceeds received from the issuance of our common stock, partially offset by net repayments under our credit agreement totaling $470.0 million, $23.1 million in debt issuance costs related to our new credit agreement, and payment of preferred stock dividends totaling $4.9 million. Cash flows from operating and financing activities, as well as $80.3 million in net proceeds from the sale of interests in certain properties primarily in the Sanish field, were used to finance $401.2 million of drilling and development expenditures paid in the first nine months of 2009 and $31.5 million of cash acquisition capital expenditures. The following chart details our exploration and development expenditures incurred by region during the first nine months of 2009 (in thousands):

	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$199,910	$12,462	$212,372	58%
Permian Basin	108,963	7,302	116,265	32%
Mid-Continent	28,861	822	29,683	8%
Gulf Coast	758	4,167	4,925	1%
Michigan	1,147	32	1,179	1%
Total incurred	339,639	24,785	364,424	100%
Decrease in accrued capital expenditures	61,588	-	61,588	
Total paid	$401,227	$24,785	$426,012	

We continually evaluate our capital needs and compare them to our capital resources. Our current 2009 capital budget for exploration and development expenditures is $470.0 million, of which we had invested $364.4 million as of September 30, 2009. We expect the remaining $105.6 million to be funded with net cash provided by our operating activities in the fourth quarter of 2009 based on prevailing oil and natural gas prices. Our 2009 capital budget of $470.0 million, however, represents a significant decrease from the $947.4 million incurred on exploration and development expenditures during 2008. This reduced capital budget is in response to significantly lower oil and natural gas prices experienced during the fourth quarter of 2008 and continuing into 2009. Although we have no specific budget for property acquisitions in 2009, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should attractive acquisition opportunities arise or exploration and development expenditures exceed $470.0 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.

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Credit Agreement. As of September 30, 2009, 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 has a borrowing base of $1.1 billion with $947.2 million of available borrowing capacity, which is net of $150.0 million in borrowings and $2.8 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2012, when the agreement expires and all outstanding borrowings are due.

The borrowing base under the renewed 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. Whiting Oil and Gas may, throughout the term of the credit agreement, borrow, repay and reborrow 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 may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of September 30, 2009, $47.2 million was available for additional letters of credit under the agreement.

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 EBITDAX ratio (as defined in the credit agreement) for the last four quarters 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 EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 2.75 to 1.0 for quarters ending prior to and on December 31, 2009 and 2.5 to 1.0 for quarters ending March 31, 2010 and thereafter. 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 dividends or distributions on our common stock or principal payments on our senior notes. We were in compliance with our covenants under the credit agreement as of September 30, 2009.

For further information on the interest rates and loan security related to our credit agreement, refer to the Long-Term Debt footnote in the Notes to Consolidated Financial Statements.

Senior Subordinated Notes. In October 2005, we issued at par $250.0 million of 7% Senior Subordinated Notes due 2014. In April 2005, we issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount is being amortized to interest expense over the term of these notes. In May 2004, we issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount is being amortized to interest expense over the term of these notes.

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, 2009. 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.

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Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liabilities since we cannot determine with accuracy the timing of future payment amounts. The following table summarizes our obligations and commitments as of September 30, 2009 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)	$ 770,000	$ -	$ 300,000	$ 470,000	$ -
Cash interest expense on debt (b)	170,043	47,804	89,601	32,638	-
Asset retirement obligation (c)	77,391	10,215	3,063	8,337	55,776
Tax sharing liability (d)	24,914	2,112	3,787	3,261	15,754
Derivative liability fair value (e)	111,247	25,050	57,468	28,729	-
Purchasing obligations (f)	148,467	35,017	71,395	39,877	2,178
Drilling rig contracts (g)	89,624	44,248	42,567	2,809	-
Operating leases (h)	12,005	2,536	6,375	3,094	-
Total	$ 1,403,691	$ 166,982	$ 574,256	$ 588,745	$ 73,708

(a) Long-term debt consists of the 7.25% Senior Subordinated Notes due 2012 and 2013, the 7% Senior Subordinated Notes due 2014 and the outstanding borrowings under our credit agreement due April 2012, and assumes no principal repayment until the due date of the instruments.

(b) Cash interest expense on the 7.25% Senior Subordinated Notes due 2012 and 2013 and the 7% Senior Subordinated Notes due 2014 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.

(e) The above derivative obligation at September 30, 2009 consists of a $15.6 million payable to Whiting USA Trust I ("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. The above derivative obligation at September 30, 2009 also consists of a $95.6 million fair value liability for derivative contracts we have entered into on our own behalf, primarily in the form of costless collars, to hedge our exposure to crude oil price fluctuations. With respect to our open derivative contracts at September 30, 2009 with certain counterparties, the forward price curves for crude oil and natural gas generally exceeded the price curves that were 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 and commodity price risk.

(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 CO_2 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 CO_2 (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. The CO_2 volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, we expect to avoid any payments for deficiencies.

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(g) We currently have six drilling rigs under long-term contract, of which three drilling rigs expire in 2010, one in 2011, one in 2012 and one in 2013. All of these rigs are operating in the Rocky Mountains region. As of September 30, 2009, early termination of the remaining contracts would require termination penalties of $57.1 million, which would be in lieu of paying the remaining drilling commitments of $89.6 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 drilling time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(h) We lease 107,400 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, 2008.

Effects of Inflation and Pricing

We experienced increased costs during 2008 due to increased demand for oil field products and services. The oil and gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

This report contains statements that we believe to be “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe” or “sho the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

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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; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption "Risk Factors" in our Quarterly Report on Form 10-Q for the period ended June 30, 2009. 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, 2008 and have not materially changed since that report was filed.

Our outstanding hedges as of October 1, 2009 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	10/2009 to 12/2009	478,000	\$61.04/\$74.89
Crude Oil	01/2010 to 03/2010	430,000	\$60.27/\$74.81
Crude Oil	04/2010 to 06/2010	415,000	\$62.69/\$80.09
Crude Oil	07/2010 to 09/2010	405,000	\$60.28/\$76.98
Crude Oil	10/2010 to 12/2010	390,000	\$60.29/\$78.23
Crude Oil	01/2011 to 03/2011	360,000	\$56.25/\$83.78
Crude Oil	04/2011 to 06/2011	360,000	\$56.25/\$83.78
Crude Oil	07/2011 to 09/2011	360,000	\$56.25/\$83.78
Crude Oil	10/2011 to 12/2011	360,000	\$56.25/\$83.78
Crude Oil	01/2012 to 03/2012	330,000	\$55.91/\$85.46
Crude Oil	04/2012 to 06/2012	330,000	\$55.91/\$85.46
Crude Oil	07/2012 to 09/2012	330,000	\$55.91/\$85.46
Crude Oil	10/2012 to 12/2012	330,000	\$55.91/\$85.46
Crude Oil	01/2013 to 03/2013	290,000	\$55.34/\$85.94
Crude Oil	04/2013 to 06/2013	290,000	\$55.34/\$85.94
Crude Oil	07/2013 to 09/2013	290,000	\$55.34/\$85.94
Crude Oil	10/2013	290,000	\$55.34/\$85.94
Crude Oil	11/2013	190,000	\$54.59/\$81.75

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (as further explained above in the note on Acquisitions and Divestitures), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 1,570 MBbls of crude oil and 5,994 MMcf of natural gas from 2009 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.

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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	10/2009 to 12/2009	46,240	$76.00/$135.72
Crude Oil	01/2010 to 03/2010	45,084	$76.00/$135.09
Crude Oil	04/2010 to 06/2010	43,978	$76.00/$134.85
Crude Oil	07/2010 to 09/2010	42,966	$76.00/$134.89
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	10/2009 to 12/2009	185,430	$7.00/$14.85
Natural Gas	01/2010 to 03/2010	178,903	$7.00/$18.65
Natural Gas	04/2010 to 06/2010	172,873	$6.00/$13.20
Natural Gas	07/2010 to 09/2010	167,583	$6.00/$14.00
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

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 change in the NYMEX forward curve as of September 30, 2009 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $63.4 million. For the natural gas contracts listed above, a hypothetical $0.50 change in the NYMEX forward curve as of September 30, 2009 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $0.3 million.

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We have various fixed price gas sales contracts with end users for a portion of the natural gas we produce in Colorado, Michigan and Utah. Our estimated future production volumes to be sold under these fixed price contracts as of October 1, 2009 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	10/2009 to 12/2009	496,333	$5.32
Natural Gas	01/2010 to 03/2010	688,000	$5.36
Natural Gas	04/2010 to 06/2010	694,667	$5.36
Natural Gas	07/2010 to 09/2010	701,333	$5.36
Natural Gas	10/2010 to 12/2010	701,333	$5.36
Natural Gas	01/2011 to 03/2011	658,000	$5.39
Natural Gas	04/2011 to 06/2011	664,333	$5.38
Natural Gas	07/2011 to 09/2011	648,667	$5.38
Natural Gas	10/2011 to 12/2011	648,667	$5.38
Natural Gas	01/2012 to 03/2012	456,000	$5.41
Natural Gas	04/2012 to 06/2012	460,333	$5.41
Natural Gas	07/2012 to 09/2012	464,667	$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, 2009. 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, 2009 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, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Risk factors relating to us are contained in Part II, Item 1A of our Quarterly Report on Form 10-Q for the period ended June 30, 2009. No material change to such risk factors has occurred during the three months ended September 30, 2009.

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, 2009.

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
(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.