WHITING PETROLEUM CORP
Form 10-Q
October 30, 2008

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, 2008

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

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

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

Number of shares of the registrant’s common stock outstanding at October 15, 2008: 42,322,978 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.

“Bbl/d” One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil and other liquid hydrocarbons per day.

“Bcf” One billion cubic feet of natural gas.

“Bcfe” One billion cubic feet of natural gas equivalent.

“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.

“flush production” The high rate of flow from a well during initial production immediately after it is brought on-line.

“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.

“Mcfe” One thousand cubic feet of natural gas equivalent.

“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.

“MMcfe/d” One million cubic feet of natural gas equivalent per day.

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"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 and 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
CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)
(In thousands)

	September 30, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 20,644	$ 14,778
Accounts receivable trade, net	192,711	110,437
Deferred income taxes	1,949	27,720
Prepaid expenses and other	26,562	9,232
Total current assets	241,866	162,167
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	4,137,940	3,313,777
Unproved properties	132,908	55,084
Other property and equipment	69,546	37,778
Total property and equipment	4,340,394	3,406,639
Less accumulated depreciation, depletion and amortization	(789,192)	(646,943)
Total property and equipment, net	3,551,202	2,759,696
DEBT ISSUANCE COSTS	11,826	15,016
OTHER LONG-TERM ASSETS	30,252	15,132
TOTAL	$ 3,835,146	$ 2,952,011

See notes to condensed consolidated financial statements. (Continued)

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

	September 30, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 40,269	$ 19,280
Accrued capital expenditures	82,840	58,988
Accrued liabilities	35,393	29,551
Accrued interest	21,222	11,240
Oil and gas sales payable	53,347	26,205
Accrued employee compensation and benefits	37,153	21,081
Production taxes payable	29,643	12,936
Current portion of deferred gain on sale	15,235	-
Current portion of tax sharing liability	2,587	2,587
Current portion of derivative liability	25,046	72,796
Total current liabilities	342,735	254,664
NON-CURRENT LIABILITIES:		
Long-term debt	1,118,560	868,248
Asset retirement obligations	42,254	35,883
Production Participation Plan liability	61,006	34,042
Tax sharing liability	24,004	23,070
Deferred income taxes	381,753	242,964
Long-term derivative liability	5,243	-
Deferred gain on sale	77,229	-
Other long-term liabilities	2,933	2,314
Total non-current liabilities	1,712,982	1,206,521
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $0.001 par value; 75,000,000 shares authorized, 42,584,833 and 42,480,497 shares issued as of September 30, 2008 and December 31, 2007, respectively	43	42
Additional paid-in capital	972,050	968,876
Accumulated other comprehensive loss	(15,867)	(46,116)
Retained earnings	823,203	568,024
Total stockholders' equity	1,779,429	1,490,826
TOTAL	$ 3,835,146	$ 2,952,011

See notes to condensed consolidated financial statements. (Concluded)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 425,392	$ 205,594	$ 1,102,658	$ 557,953
Loss on oil hedging activities	(41,879)	(2,101)	(112,902)	(2,101)
Gain on sale of properties	-	29,682	-	29,682
Amortization of deferred gain on sale	4,720	-	7,677	-
Interest income and other	201	353	825	821
Total revenues and other income	388,434	233,528	998,258	586,355
COSTS AND EXPENSES:				
Lease operating	64,690	53,472	177,866	154,512
Production taxes	28,245	13,197	71,988	34,888
Depreciation, depletion and amortization	74,233	49,308	179,555	143,214
Exploration and impairment	10,939	10,420	30,566	26,239
General and administrative	17,281	10,780	51,903	27,941
Change in Production Participation Plan liability	9,117	2,254	26,964	6,404
Interest expense	17,543	16,263	48,760	56,514
(Gain) loss on mark-to-market derivatives	(10,561)	487	7,064	1,178
Total costs and expenses	211,487	156,181	594,666	450,890
INCOME BEFORE INCOME TAXES	176,947	77,347	403,592	135,465
INCOME TAX EXPENSE:				
Current	481	3,401	1,353	5,542
Deferred	64,049	26,233	147,060	45,073
Total income tax expense	64,530	29,634	148,413	50,615
NET INCOME	$ 112,417	$ 47,713	$ 255,179	$ 84,850
NET INCOME PER COMMON SHARE, BASIC	$ 2.66	$ 1.14	$ 6.03	$ 2.20
NET INCOME PER COMMON SHARE, DILUTED	$ 2.65	$ 1.13	$ 6.01	$ 2.19
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	42,322	42,027	42,305	38,555
	42,465	42,152	42,464	38,728

WEIGHTED AVERAGE SHARES
OUTSTANDING, DILUTED

See notes to condensed consolidated financial statements.

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

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 255,179	$ 84,850
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	179,555	143,214
Deferred income taxes	147,060	45,073
Amortization of debt issuance costs and debt discount	3,618	3,793
Accretion of tax sharing liability	934	1,142
Stock-based compensation	4,917	3,652
Gain on sale of properties	-	(29,682)
Amortization of deferred gain on sale	(7,677)	-
Unproved leasehold and oil and gas property impairments	9,016	7,158
Change in Production Participation Plan liability	26,964	6,404
Unrealized loss on mark-to-market derivatives	7,021	1,178
Other non-current	(14,744)	(3,596)
Changes in current assets and liabilities:		
Accounts receivable trade	(77,398)	2,591
Prepaid expenses and other	(17,836)	3,654
Accounts payable and accrued liabilities	26,683	(13,301)
Accrued interest	9,982	15,113
Other current liabilities	58,178	1,366
Net cash provided by operating activities	611,452	272,609
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(413,219)	(16,780)
Drilling and development capital expenditures	(638,400)	(353,686)
Proceeds from sale of oil and gas properties	1,445	45,419
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	(855,586)	(325,047)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	-	210,394
Long-term borrowings under credit agreement	925,000	274,400
Repayments of long-term borrowings under credit agreement	(675,000)	(434,400)
Tax effect from restricted stock vesting	-	377
Net cash provided by financing activities	250,000	50,771
NET CHANGE IN CASH AND CASH EQUIVALENTS	5,866	(1,667)
CASH AND CASH EQUIVALENTS:		
Beginning of period	14,778	10,372
End of period	$ 20,644	$ 8,705

SUPPLEMENTAL CASH FLOW DISCLOSURES:				
Cash paid for income taxes	$	1,175	$	1,717
Cash paid for interest	$	34,227	$	36,467
NONCASH INVESTING ACTIVITIES:				
Accrued capital expenditures during the period	$	82,840	$	45,038

See notes to condensed consolidated financial statements.

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

	Common Stock						
	Shares	Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity	Comprehensive Income
BALANCES-January 1, 2007	36,948	$ 37	$ 754,788	$ (5,902)	$ 437,747	$ 1,186,670	
Adoption of FIN 48	-	-	-	-	(323)	(323)	$ -
Net income	-	-	-	-	130,600	130,600	130,600
Change in derivative fair values, net of taxes of $31,012	-	-	-	(53,637)	-	(53,637)	(53,637)
Realized loss on settled derivative contracts, net of taxes of $7,766	-	-	-	13,423	-	13,423	13,423
Issuance of stock, secondary offering	5,425	5	210,389	-	-	210,394	-
Restricted stock issued	150	-	-	-	-	-	-
Restricted stock forfeited	(12)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(31)	-	(1,403)	-	-	(1,403)	-
Tax effect from restricted stock vesting	-	-	45	-	-	45	-
Stock-based compensation	-	-	5,057	-	-	5,057	-
BALANCES-December 31, 2007	42,480	$ 42	$ 968,876	$ (46,116)	$ 568,024	$ 1,490,826	$ 90,386
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
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	$ 285,428

See notes to condensed consolidated financial statements.

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WHITING PETROLEUM CORPORATION
NOTES TO CONDENSED 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 condensed 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. The financial statements have been prepared in accordance with U.S. generally accepted accounting principles for interim financial reporting. All intercompany balances and transactions have been eliminated in consolidation. 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 2007 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 2007 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 net income by the weighted average number of common shares outstanding during each period. Diluted net income per common share is calculated by dividing net income by the weighted average number of common shares outstanding and other dilutive securities. The only securities considered dilutive are the Company's unvested restricted stock awards.

2. ACQUISITIONS AND DIVESTITURES

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 22,029 gross acres (11,533 net acres) in the Flat Rock field in Uintah County, Utah for an aggregate acquisition price of $359.4 million. After allocating $79.5 million of the purchase price to unproved property, $35.7 million to the gas gathering and processing facilities and $7.7 million to liabilities assumed, the remaining $251.9 million results in an acquisition cost for proved reserves of $2.19 per Mcfe. Of the estimated 115.2 Bcfe of proved reserves acquired as of the January 1, 2008 acquisition effective date, 98% are natural gas and 22% are proved developed producing. The average daily net production from the properties was 17.8 MMcfe/d as of the acquisition effective date. Whiting funded the acquisition with borrowings under its credit agreement.

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This acquisition was recorded using the purchase method of accounting. The table below summarizes the allocation of 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 condensed consolidated statements of income, 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 and for the three and nine months ended September 30, 2007, as though the Flat Rock acquisition had occurred on the first day of each period presented. 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.

		Pro Forma	
	Whiting (As reported)	Flat Rock	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
Three months ended September 30, 2007:			
Total revenues	$ 233,528	$ 3,803	$ 237,331
Net income	47,713	(2,126)	45,587
Net income per common share – basic	1.14	(0.06)	1.08
Net income per common share – diluted	1.13	(0.05)	1.08

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	Whiting (As reported)	Pro Forma Flat Rock	Consolidated
Nine months ended September 30, 2007:			
Total revenues	$ 586,355	$ 18,538	$ 604,893
Net income	84,850	(3,216)	81,634
Net income per common share – basic	2.20	(0.08)	2.12
Net income per common share – diluted	2.19	(0.08)	2.11

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 $215.0 million after underwriters’ discount and commissions and offering related expenses. Whiting’s net profits from the Trust’s underlying oil and gas properties received between the effective date and the closing date of the Trust unit sale were paid to the Trust and thereby further reduced net proceeds to $193.8 million. The Company used the net offering proceeds to reduce the debt outstanding under its credit agreement. The aggregate 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 natural 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, 2017 based on the reserve report for the underlying properties as of December 31, 2007. The conveyance of the net profits interest to the Trust consisted entirely of proved developed producing reserves of 8.2 MMBOE, as of the January 1, 2008 effective date, representing 3.3% of Whiting’s proved reserves as of December 31, 2007, and 10.0%, or 4.2 MBOE/d, of its March 2008 average daily net production. After netting the Company’s ownership of 2,186,389 Trust units, third-party public Trust unit holders receive 6.9 MMBOE of proved producing reserves, or 2.75% of the Company’s total year-end 2007 proved reserves, and 7.4%, or 3.1 MBOE/d, of its March 2008 average daily net production.

2007 Acquisitions

There were no significant acquisitions during the year ended December 31, 2007.

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2007 Divestitures

On July 17, 2007, the Company sold its approximate 50% non-operated working interest in several gas fields located in the LaSalle and Webb Counties of Texas for total cash proceeds of $40.1 million, resulting in a pre-tax gain on sale of $29.7 million. The divested properties had estimated proved reserves of 2.3 MMBOE as of December 31, 2006, and when adjusted to the July 1, 2007 divestiture effective date, the divested property reserves yielded a sale price of $17.77 per BOE. The June 2007 average daily net production from these fields was 0.8 MBOE/d.

During 2007, the Company sold its interests in several additional non-core oil and gas producing properties for an aggregate amount of $12.5 million in cash for total estimated proved reserves of 0.6 MMBOE as of the divestitures' effective dates. The divested properties are located in Colorado, Louisiana, Michigan, Montana, New Mexico, North Dakota, Oklahoma, Texas and Wyoming. The average daily net production from the divested property interests was 0.3 MBOE/d as of the dates of disposition.

3. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2008 and December 31, 2007 (in thousands):

	September 30, 2008	December 31, 2007
Credit Agreement	$ 500,000	$ 250,000
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,645 and $1,966, respectively	218,355	218,034
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $429 and $537, respectively	150,205	150,214
Total debt	$ 1,118,560	$ 868,248

Credit Agreement—The Company's wholly-owned subsidiary, Whiting Oil and Gas Corporation ("Whiting Oil and Gas") has a $1.2 billion credit agreement with a syndicate of banks that, as of September 30, 2008, had a borrowing base of $900.0 million with $397.3 million of available borrowing capacity, which is net of $500.0 million in borrowings and $2.7 million in letters of credit outstanding. 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.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas may, throughout the five-year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company in an aggregate amount not to exceed $50.0 million. As of September 30, 2008, $47.3 million was available for additional letters of credit under the agreement.

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Interest accrues, at Whiting Oil and Gas' option, at either (1) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage, and are included as a component of interest expense. At September 30, 2008, the weighted average interest rate on the outstanding principal balance under the credit agreement was 3.9%.

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders and requires the Company to maintain a debt to EBITDAX ratio (as defined in the credit agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit facility) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and Whiting Petroleum Corporation's wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions, principal payments on senior notes, or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. The Company was in compliance with its covenants under the credit agreement as of September 30, 2008. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for its guarantee, and Equity Oil Company has mortgaged all of its properties, that are included in the borrowing base for the credit agreement, 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 $207.5 million as of September 30, 2008, 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 $195.5 million as of September 30, 2008, 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 $134.6 million as of September 30, 2008, based on quoted market prices for these same debt securities.

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The notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of Whiting Oil and Gas' credit agreement. The indentures governing the notes contain various restrictive covenants that are substantially identical and may limit the Company's ability to, among other things, pay cash dividends, redeem or repurchase the Company's capital stock or the Company's subordinated debt, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of the Company's management in certain respects. The Company was in compliance with these covenants as of September 30, 2008. The Company's wholly-owned operating subsidiaries, Whiting Oil and Gas, Whiting Programs, Inc. and Equity Oil Company (the "Guarantors"), have fully, unconditionally, jointly and severally guaranteed the Company's obligations under the notes. The Company does not have any subsidiaries other than the Guarantors, minor or otherwise, within the meaning of Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission, and 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. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that the Company receives the fixed rate of 7.25% and pays the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus the Company's margin of 2.345% is less than 7.25%, the Company receives a payment from the counterparty equal to the difference in rate times $75.0 million for the six month period. When LIBOR plus the Company's margin of 2.345% is greater than 7.25%, the Company pays the counterparty an amount equal to the difference in rate times $75.0 million for the six month period. As of September 30, 2008, the Company has recorded a long term asset of $0.6 million related to the interest rate swap, which has been designated as a fair value hedge, with an offsetting increase to the fair value of the 7.25% Senior Subordinated Notes due 2012.

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 asset retirement obligations by calculating the present value of estimated cash flows related to plug and abandonment obligations. The current portions at September 30, 2008 and December 31, 2007 were $1.4 million and $1.3 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, 2008 (in thousands):

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Asset retirement obligation, January 1, 2008	$	37,192
Additional liability incurred		2,944
Revisions in estimated cash flows		5,695
Accretion expense		2,341
Obligations on sold or conveyed properties		(537)
Liabilities settled		(3,951)
Asset retirement obligation, September 30, 2008	$	43,684

5. DERIVATIVE FINANCIAL INSTRUMENTS

Whiting enters into derivative contracts, primarily costless collars, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. 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 has designated a portion of its derivative contracts as cash flow hedges, whose unrealized fair value gains and losses are recorded to other comprehensive income, while the Company's remaining derivative contracts are not designated as hedges, with gains and losses from changes in fair value recognized immediately in earnings. The Company does not enter into derivative instruments for speculative or trading purposes.

At September 30, 2008, accumulated other comprehensive loss consisted of $25.0 million ($15.9 million after tax) of unrealized losses, representing the mark-to-market value of the Company's open commodity contracts designated as cash flow hedges as of the balance sheet date. For the three and nine months ended September 30, 2008, Whiting recognized realized cash settlement losses of $41.9 million and $112.9 million, respectively, on commodity derivative settlements. For the three and nine months ended September 30, 2007, Whiting recognized realized cash settlement losses of $2.1 million on commodity derivative settlements. Based on the estimated fair value of the Company's derivative contracts designated as hedges at September 30, 2008, the Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax losses of $15.9 million during the next three months, as all costless collars designated as cash flow hedges will expire by December 31, 2008. However, actual cash settlement gains and losses recognized may differ materially.

As of October 1, 2008, the Company had entered into costless collar derivative contracts to reduce its exposure to commodity price volatility as follows:

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	Whiting Petroleum Corporation			
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
October 2008	342,448	55,377	$58.41 - $77.62	$7.00 - $19.00
November 2008	342,448	55,377	$58.41 - $77.62	$7.00 - $19.00
December 2008	342,448	55,377	$58.41 - $77.62	$7.00 - $19.00
Total	1,027,344	166,131		

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 hedge contracts conveyed to the Trust. The relative ownership of the future economic results of such hedge contracts is reflected in the tables below. No additional hedges are allowed to be placed on Trust assets.

The 24.2% portion of Trust derivative contracts that are absorbed by Whiting 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)
4th Quarter 2008	37,343	166,131	$82.00 - $131.58	$7.00 - $19.00
2009	139,873	577,820	$76.00 - $137.43	$6.50 - $17.11
2010	126,289	495,390	$76.00 - $134.98	$6.50 - $15.06
2011	115,039	436,510	$74.00 - $140.15	$6.50 - $14.62
2012	105,091	384,002	$74.00 - $141.72	$6.50 - $14.27
Total	523,635	2,059,853		

The 75.8% portion of Trust derivative contracts that are absorbed by third-party public holders of Trust units 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)
4th Quarter 2008	116,965	520,359	$82.00 - $131.58	$7.00 - $19.00

2009	438,113	1,809,868	$76.00 - $137.43	$6.50 - $17.11
2010	395,567	1,551,678	$76.00 - $134.98	$6.50 - $15.06
2011	360,329	1,367,249	$74.00 - $140.15	$6.50 - $14.62
2012	329,171	1,202,785	$74.00 - $141.72	$6.50 - $14.27
Total	1,640,145	6,451,939		

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With respect to costless collars entered into by Whiting for which the economic benefits and detriments were conveyed to the Trust, the Company has recorded a non-current liability of $5.2 million, with a corresponding non-current asset of $4.0 million recorded in other long-term assets.

The Company has also entered into an interest rate swap designated as a fair value hedge as further explained in the note on Long-Term Debt.

6. FAIR VALUE DISCLOSURES

SFAS 157—Effective January 1, 2008, the Company adopted Financial Accounting Standards Board ("FASB") Statement No. 157, Fair Value Measurements ("SFAS 157"), which defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements. The implementation of SFAS 157 did not cause a change in the method of calculating fair value of assets or liabilities, with the exception of incorporating a measure of the Company's own nonperformance risk or that of its counterparties as appropriate, which was not material. The primary impact from adoption was additional disclosures.

The Company elected to implement SFAS 157 with the one-year deferral permitted by FASB Staff Position No. FAS 157-2, Effective Date of FASB Statement No. 157 ("FSP 157-2"), issued February 2008, which defers the effective date of SFAS 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis. As it relates to the Company, the deferral 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.

Fair Value Hierarchy—SFAS 157 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, 2008, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Level 1	Level 2	Level 3	September 30, 2008
Assets				
Other long-term assets (1) (2)	$ -	$ 4,611	$ -	$ 4,611
Total	$ -	$ 4,611	$ -	$ 4,611
Liabilities				
Current portion of derivative liability	$ -	$ 25,046	$ -	$ 25,046
Long-term derivative liability	-	5,243	-	5,243
Long-term debt (1)	-	636	-	636
Total	$ -	$ 30,925	$ -	$ 30,925

(1) Amount includes $636 related to interest rate swap (see note on Long-Term Debt).

(2) Amount includes $3,975 related to non-current derivative assets.

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

Commodity Derivative Instruments—Commodity derivative instruments consist of costless collars for crude oil and natural gas. The Company's costless collars are valued based on the counterparty's marked-to-market statements, which are validated by observable transactions for the same or similar commodity options using the NYMEX futures index, and are 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.

Interest Rate Swap—The Company's interest rate swap is valued using the counterparty's marked-to-market statement, which can be validated using modeling techniques that include market inputs such as publicly available interest rate yield curves, and is designated as Level 2 within the valuation hierarchy.

SFAS 159—In February 2007, the FASB issued Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115 ("SFAS 159"). SFAS 159 expands the use of fair value accounting but does not affect existing standards which require assets or liabilities to be carried at fair value. On January 1, 2008, the Company adopted SFAS 159 and did not elect fair value accounting for any of its eligible items. The adoption of SFAS 159 therefore had no impact on the Company's consolidated financial position, cash flows or results of operations. If the use of fair value is elected (the fair value option), however, any upfront costs and fees related to the item must be recognized in earnings and cannot be deferred, e.g., debt issue costs. The fair value election is irrevocable and generally made on an instrument-by-instrument basis, even if a company has similar instruments that it elects not to measure based on fair value. Subsequent to the adoption of SFAS 159, changes in fair value are recognized in earnings.

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7. STOCKHOLDERS' EQUITY

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the "Plan"), pursuant to which two million shares of the Company's common stock have been reserved for issuance. No employee or officer participant may be granted options for more than 300,000 shares of common stock, stock appreciation rights with respect to more than 300,000 shares of common stock, or more than 150,000 shares of restricted stock during any calendar year.

Restricted stock awards for executive officers, directors and employees generally vest ratably over three years. However, restricted stock awards granted to executive officers in February 2007 and 2008 included certain performance conditions, in addition to the standard three-year service condition, that must be met in order for the stock awards to vest. The Company believes that it is probable that such performance conditions will be achieved and has accrued compensation cost accordingly for its 2007 and 2008 restricted stock grants to executives.

The following table shows a summary of the Company's nonvested restricted stock as of September 30, 2008 as well as activity during the nine months then ended (share and per share data, not presented in thousands):

	Number of Shares	Weighted Average Grant Date Fair Value
Restricted stock awards nonvested, January 1, 2008	239,656	$ 44.15
Granted	138,518	$ 58.35
Vested	(112,026)	$ 43.43
Forfeited	(4,293)	$ 51.00
Restricted stock awards nonvested, September 30, 2008	261,855	$ 51.86

The grant date fair value of restricted stock is determined based on the closing bid price of the Company's common stock on the grant date. The Company uses historical data and projections to estimate expected employee behaviors related to restricted stock forfeitures. The expected forfeitures are then included as part of the grant date estimate of compensation cost.

As of September 30, 2008, there was $6.3 million of total unrecognized compensation cost related to unvested restricted stock granted under the stock incentive plans. That cost is expected to be recognized over a weighted average period of 2.2 years.

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Rights Agreement—In 2006, the Board of Directors of the Company declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of common stock of the Company payable to the stockholders of record as of March 2, 2006. Each Right entitles the registered holder to purchase from the Company one one-hundredth of a share of Series A Junior Participating Preferred Stock, par value $0.001 per share ("Preferred Shares"), of the Company at a price of $180.00 per one one-hundredth of a Preferred Share, subject to adjustment. If any person becomes a 15% or more stockholder of the Company, then each Right (subject to certain limitations) will entitle its holder to purchase, at the Right's then current exercise price, a number of shares of common stock of the Company or of the acquirer having a market value at the time of twice the Right's per share exercise price. The Company's Board of Directors may redeem the Rights for $0.001 per Right at any time prior to the time when the Rights become exercisable. Unless the Rights are redeemed, exchanged or terminated earlier, they will expire on February 23, 2016.

8. EMPLOYEE BENEFIT PLANS

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, 2008 and 2007 amounted to $30.0 million and $11.3 million, respectively, charged to general and administrative expense and $4.7 million and $1.8 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, (1) employees who terminate their employment with the Company are entitled to receive their vested allocation of future Plan year payments on an annual basis; (2) employees will become fully vested at age 62, regardless of when their interests would otherwise vest; and (3) any forfeitures inure to the benefit of the Company.

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At September 30, 2008, the Company used three-year average historical NYMEX prices of $75.76 for crude oil and $7.41 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, 2008, 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 $188.8 million. This amount includes $37.1 million attributable to proved undeveloped oil and gas properties and $34.7 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2009. 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.

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The following table presents changes in the estimated long-term liability related to the Plan for the nine months ended September 30, 2008 (in thousands):

Production Participation Plan liability, January 1, 2008	$	34,042
Change in liability for accretion, vesting and changes in estimates		61,647
Reduction in liability for cash payments accrued and recognized as compensation expense		(34,683)
Production Participation Plan liability, September 30, 2008	$	61,006

The Company records the expense associated with changes in the present value of estimated future payments under the Plan as a separate line item in the condensed consolidated statements of income. The amount recorded is not allocated to general and administrative expense or exploration expense because the adjustment of the liability is associated with the future net cash flows from the oil and gas properties rather than current period performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items (in thousands).

	Nine Months Ended September 30,			
		2008		2007
General and administrative expense	$	23,297	$	5,499
Exploration expense		3,667		905
Total	$	26,964	$	6,404

401(k) Plan—The Company has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. Employees vest in employer contributions at 20% per year of completed service.

9. RELATED PARTY TRANSACTIONS

Whiting USA Trust I—As a result of Whiting's retained ownership of 15.8%, or 2,186,389 units in Whiting USA Trust I, the Trust is a related party of the Company as of September 30, 2008. The following table summarizes the related party receivable and payable balances between the Company and the Trust as of September 30, 2008 and December 31, 2007 (in thousands):

		September 30, 2008		December 31, 2007
Assets				
Unit distributions due from Trust (1)	$	2,531	$	-
Non-current derivative asset (2)		3,975		-
Total	$	6,506	$	-
Liabilities				
Unit distributions payable to Trust (3)	$	15,603	$	-
Total	$	15,603	$	-

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(1) This amount is included within Prepaid Expenses and Other in the Company's condensed consolidated balance sheet.
(2) This amount is included within Other Long-term Assets in the Company's condensed consolidated balance sheet.
(3) This amount primarily represents net proceeds from the Trust's underlying properties, that the Company has received between the last Trust distribution date and September 30, 2008, but which the Company has not yet distributed to the Trust as of September 30, 2008. Due to ongoing processing of Trust revenues and expenses after September 30, 2008, the amount of Whiting's next scheduled distribution to the Trust, and the related distribution by the Trust to its unit holders, will differ from this amount. This amount is included within Accrued Liabilities in the Company's condensed consolidated balance sheet.

For the three and nine months ended September 30, 2008, Whiting paid $21.4 million and $36.1 million, respectively, net of state tax withholdings, in unit distributions to the Trust and received $3.3 million and $5.6 million, respectively, in distributions back from the Trust pursuant to its retained ownership in 2,186,389 Trust units.

Tax Sharing Liability—Prior to Whiting's initial public offering in November 2003, it was a wholly-owned indirect subsidiary of Alliant Energy Corporation ("Alliant Energy"), a holding company whose primary businesses are utility companies. When the transactions discussed below were entered into, Alliant Energy was a related party of the Company. As of December 31, 2004 and thereafter, Alliant Energy was no longer a related party.

In connection with Whiting's initial public offering in November 2003, the Company entered into a Tax Separation and Indemnification Agreement with Alliant Energy. Pursuant to this agreement, the Company and Alliant Energy made a tax election with the effect that the tax bases of Whiting's assets were increased to the deemed purchase price of their assets immediately prior to such initial public offering. Whiting has adjusted deferred taxes on its balance sheet to reflect the new tax bases of its assets. The additional bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by Whiting.

Under this agreement, the Company has agreed to pay to Alliant Energy 90% of the future tax benefits the Company realizes annually as a result of this step-up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing the Company's actual taxes to the taxes that would have been owed by the Company had the increase in basis not occurred. In 2014, Whiting 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. The Company has estimated total payments to Alliant will approximate $34.7 million on an undiscounted basis.

During the first nine months of 2008, the Company did not make any payments under this agreement but did recognize $0.9 million of discount accretion, which is included as a component of interest expense. The Company's estimated payment of $2.6 million to be made in 2008 under this agreement is reflected as a current liability at September 30, 2008.

The Tax Separation and Indemnification Agreement provides that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in a corresponding adjustment of the tax sharing liability. For purposes of this calculation, management has assumed that no such future changes will occur during the term of this agreement.

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The Company periodically evaluates its estimates and assumptions as to future payments to be made under this agreement. If non-substantial changes (less than 10% on a present value basis) are made to the anticipated payments owed to Alliant Energy, a new effective interest rate is determined for this debt based on the carrying amount of the liability as of the modification date and based on the revised payment schedule. However, if there are substantial changes to the estimated payments owed under this agreement, then a gain or loss is recognized in the consolidated statements of income during the period in which the modification has been made.

Alliant Energy Guarantee—The Company holds a 6% working interest in three offshore platforms and related onshore plant and equipment in California. Alliant Energy has guaranteed the Company's obligation in the abandonment of these assets.

10. COMMITMENTS AND CONTINGENCIES

Non-cancelable Leases—The Company leases 107,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2013 and an additional 46,700 square feet of office space in Midland, Texas through March 7, 2012. Rental expense for the first nine months of 2008 and 2007 was $1.5 million and $1.6 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of September 30, 2008 are as follows (in thousands):

2008	$	583
2009		2,520
2010		2,677
2011		3,383
2012		2,931
Thereafter		2,383
Total	$	14,477

Purchase Contracts—The Company has entered into two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement expiring in December 2014, whereby the Company has committed to buy certain volumes of CO_2 for a fixed fee subject to annual escalation. The purchase agreements are with different suppliers, and the CO_2 is for use in enhanced recovery projects in the Postle field in Texas County, Oklahoma and the North Ward Estes field in Ward County, Texas. Under the terms of the agreements, the Company is 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 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, the Company expects to avoid any payments for deficiencies. As of September 30, 2008, future commitments under the purchase agreements amounted to $241.0 million through 2014.

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Drilling Contracts—The Company has one drilling rig under contract through 2008, six drilling rigs through 2009, four drilling rigs through 2010, two drilling rigs through 2012 and one workover rig under contract through 2009, all of which are operating in the Rocky Mountains region. As of September 30, 2008, these agreements had total commitments of $178.0 million and early termination would require maximum penalties of $98.4 million. Other drilling rigs working for the Company are not under long-term contracts but instead are under contracts that can be terminated at the end of the well that is currently being drilled.

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

11. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In March 2008, the FASB issued Statement No. 161, Disclosure about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133 ("SFAS 161"). The adoption of SFAS 161 is not expected to have an impact on the Company's consolidated financial statements, other than additional disclosures. 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. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51 ("SFAS 160"). As Whiting currently does not have any minority interests, the Company does not expect the adoption of SFAS 160 to have an impact on its consolidated financial statements. This statement amends ARB No. 51 and intends to improve the relevance, comparability, and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards of the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. SFAS 160 is effective for fiscal years, and interim periods, beginning on or after December 15, 2008.

In December 2007, the FASB issued Statement No. 141R, Business Combinations ("SFAS 141R"). SFAS 141R may have an impact on the Company's consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions the Company consummates after the effective date. SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in business combinations and determines what information to disclose to enable users of the financial statement to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008.

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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, Equity Oil Company 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 current production levels and provided upside potential through further development. Since 2006, we have focused our drilling activity on the development of these acquired properties, specifically on projects that we believe provide repeatable successes in particular fields. Our combination of acquisitions and subsequent development allows us to direct our capital resources to what we believe to be the most advantageous investments.

As demonstrated by our recent capital expenditures, 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, provide 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 an increasing percentage of our capital budget to leasing and testing new 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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Our revenue, profitability and future growth rate depend on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for crude oil or natural gas could materially and adversely affect our financial position, cash flows, results of operations, access to capital, and the quantities of oil and gas reserves that we can economically produce.

Crude oil and natural gas prices have fallen significantly since their third quarter 2008 levels. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may materially and adversely affect our future business, 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.

2008 Highlights and Future Considerations

On April 30, 2008, we 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, and providing net proceeds of $215.0 million after underwriters' discount and commissions and offering related expenses. Our net profits from the Trust's underlying oil and gas properties received between the effective date and the closing date of the Trust unit sale were paid to the Trust and thereby further reduced net proceeds to $193.8 million. We used the offering net proceeds to reduce the debt outstanding under our credit agreement. The aggregate 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, we conveyed a term net profits interest in certain of our oil and natural gas properties to the Trust in exchange for 13,863,889 Trust units. We have 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, 2017 based on the reserve report for the underlying properties as of December 31, 2007. The conveyance of the net profits interest to the Trust consisted entirely of proved developed producing reserves of 8.2 MMBOE, as of the January 1, 2008 effective date, representing 3.3% of our proved reserves as of December 31, 2007, and 10.0% (4.2 MBOE/d) of our March 2008 average daily net production. After netting our ownership of 2,186,389 Trust units, third-party public Trust unit holders receive 6.9 MMBOE of proved producing reserves, or 2.75% of our total year-end 2007 proved reserves, and 7.4% (3.1 MBOE/d) of our March 2008 average daily net production.

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On May 30, 2008, we acquired interests in 31 producing gas wells, development acreage and gas gathering and processing facilities on 22,029 gross acres (11,533 net acres) in the Flat Rock field in Uintah County, Utah for an aggregate acquisition price of $359.4 million. After allocating $79.5 million of the purchase price to unproved property, $35.7 million to the gas gathering and processing facilities, and $7.7 million to liabilities assumed, the remaining $251.9 million results in an acquisition cost for the proved reserves of $2.19 per Mcfe. Of the estimated 115.2 Bcfe of proved reserves acquired as of the January 1, 2008 acquisition effective date, 98% are natural gas, and 22% are proved developed producing. The average daily net production from the properties was 17.8 MMcfe/d as of the acquisition effective date. We funded the acquisition with borrowings under our credit agreement.

Our Sanish field in Mountrail County, North Dakota encompasses 118,571 gross acres (83,310 net acres). September 2008 net production in the Sanish field averaged 5.9 MBOE/d, a 72% increase from 3.4 MBOE/d in June 2008. At the end of September 2008, we were drilling or completing five operated wells in the Sanish field with an average working interest of 86% and had five operated rigs working in the field. We expect to have eight operated rigs drilling in the area by year-end 2008. We have completed 18 operated wells in the Sanish field in 2008 and expect to complete an additional 14 to 16 wells during the balance of the year.

We completed construction of the first phase of a natural gas processing plant that will separate the natural gas liquids (“NGLs”) from the natural gas produced from Sanish field. In August 2008, we completed the installation of a 17-mile pipeline to transport the natural gas and natural gas liquids to a sales point in Stanley, North Dakota. At the end of September 2008, natural gas sales from the plant were averaging approximately 1.0 MMcf/d and net NGL sales were averaging approximately 130 Bbl/d.

Immediately east of the Sanish field is the Parshall field, where we own interests in 72,790 gross acres (14,982 net acres). We have participated in the drilling and completion of 64 wells that produce from the Bakken formation, 40 of which were completed in 2008. We expect to participate in the drilling of an additional 20 to 30 wells in the Parshall field during 2008, with an average working interest of 25%. Four drilling rigs are expected to be working in the Parshall field through 2008. Our net production from the Parshall field averaged 6.6 MBOE/d in September 2008, a 31% increase from 5.0 MBOE/d in June 2008.

We hold interests in 2,760 gross acres (1,570 net acres) in our Boies Ranch and Jimmy Gulch prospects in the Piceance Basin of Rio Blanco County, Colorado. In the Piceance, we have 15 wells that had a combined net production rate of 9.5 MMcf/d of gas during September 2008, a 56% increase from 6.1 MMcf/d in June 2008. Whiting holds an average working interest of 72% and an average net revenue interest of 63% in these gas wells. We plan to drill a total of 185 wells in the Piceance. We also own an average 16% working interest in a federal lease consisting of an additional 14,133 acres in the area.

We recently completed a pipeline at our Boies Ranch prospect, and the newly completed line connects to a supply trunk line, which in turn feeds a treating and processing facility that is ultimately connected to the Rockies Express pipeline (REX). REX gives us access to multiple intrastate and interstate markets, and our new pipeline connection will allow us to market all of our gas at Boies Ranch without restriction. We made alternative marketing arrangements for our Piceance Basin gas production in September 2008 to mitigate the impact of pipeline capacity reductions due to testing on a section of the REX pipeline for most of the month.

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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. During the first nine months of 2008, we incurred $248.1 million of development expenditures on these two projects.

Our expansion of the CO2 flood at the Postle field, located in Texas County, Oklahoma, continues to generate positive results. Production from the field has increased 17% from a net 5.8 MBOE/d in December 2007 to a net 6.8 MBOE/d in September 2008. This project is part of the Company’s plan to expand the existing water and CO2 flood from the eastern half of the Postle field to the western half of the field.

In 2007, we initiated our CO2 flood in the North Ward Estes field, located in Ward and Winkler Counties, Texas. Net production from North Ward Estes in September 2008 averaged 6.6 MBOE/d, a 31% increase from 5.1 MBOE/d in December 2007.

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Results of Operations

Nine Months Ended September 30, 2008 Compared to Nine Months Ended September 30, 2007

Selected Operating Data:	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Net production:		
Oil (MMbbls)	8.7	7.1
Natural gas (Bcf)	22.4	23.3
Total production (MMBOE)	12.4	11.0
Net sales (in millions):		
Oil (1)	$ 904.1	$ 414.8
Natural gas (1)	198.6	143.2
Total oil and natural gas sales	$ 1,102.7	$ 558.0
Average sales prices:		
Oil (per Bbl)	$ 104.21	$ 58.37
Effect of oil hedges on average price (per Bbl)	(13.01)	(0.29)
Oil net of hedging (per Bbl)	$ 91.20	$ 58.08
Average NYMEX price	$ 113.38	$ 66.12
Natural gas (per Mcf)	$ 8.87	$ 6.14
Effect of natural gas hedges on average price (per Mcf)	-	-
Natural gas net of hedging (per Mcf)	$ 8.87	$ 6.14
Average NYMEX price	$ 9.75	$ 6.83
Cost and expense (per BOE):		
Lease operating expenses	$ 14.33	$ 14.05
Production taxes	$ 5.80	$ 3.17
Depreciation, depletion and amortization expense	$ 14.47	$ 13.02
General and administrative expenses	$ 4.18	$ 2.54

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $544.7 million to $1,102.7 million for the first nine months of 2008 compared to the same period in 2007. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 22% between periods, while our gas sales volumes decreased 4%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area, in addition to increased production at our two large CO_2 projects, Postle and North Ward Estes. Oil production from the Bakken increased 1,680 Mbbl compared to the first nine months of 2007, while Postle oil production increased 295 Mbbl and North Ward Estes oil production increased 90 Mbbl over the same period in 2007. These production increases were partially offset by the Whiting USA Trust I (the "Trust") divestiture, which decreased oil production by 595 Mbbl. The gas volume decline between periods was primarily the result of the Trust divestiture, which decreased gas production in 2008 by 2,740 MMcf, and property dispositions in the second half of 2007, which decreased gas production in 2008 by an additional 775 MMcf. These decreases were partially offset by incremental gas production of 1,870 MMcf from the Flat Rock acquisition and higher production in the Boies Ranch area of 995 MMcf. Our average price for oil before effects of hedging increased 79% between periods, and our average price for natural gas before effects of hedging increased 44%.

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Loss on Oil Hedging Activities. We hedged 39% of our oil volumes during the first nine months of 2008, incurring cash settlement losses of $112.9 million, and 54% of our oil volumes during the first nine months of 2007, incurring cash settlement losses of $2.1 million. We hedged 1% of our gas volumes during the first nine months of 2008 and 21% of our gas volumes during the same period in 2007, incurring no cash settlement gains or losses in either period. See Item 3, “Qualitative and Quantitative Disclosures About Market Risk” for a list of our outstanding oil and natural gas hedges as of October 1, 2008.

Gain on Sale of Properties. There was no gain or loss on the sale of properties during the nine months ended September 30, 2008. During the nine months ended September 30, 2007, however, we sold certain non-core properties for aggregate sales proceeds of $45.4 million, resulting in a pre-tax gain on sale of $29.7 million.

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

Lease Operating Expenses. Our lease operating expenses during the first nine months of 2008 were $177.9 million, a $23.4 million (15%) increase over the same period in 2007. Our lease operating expenses per BOE increased from $14.05 during the first nine months of 2007 to $14.33 during the first nine months of 2008. The increase of 2% on a BOE basis was primarily caused by inflation in the cost of oil field goods and services and a high level of workover activity, which factors were partially offset by flush production from Bakken drilling. Workovers amounted to $17.8 million in the first nine months of 2008, as compared to $11.3 million in the first nine months of 2007.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for the first nine months of 2008 and 2007 were 6.5% and 6.3%, respectively, of oil and gas sales. Our production tax rate for the first nine months of 2008 was greater than the rate for same period in 2007 due to the change in property mix associated with recent divestitures in low tax rate jurisdictions and drilling successes in higher tax rate jurisdictions.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense increased $36.3 million as compared to the first nine months of 2007. The components of our DD&A expense were as follows (in thousands):

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	Nine Months Ended September 30, 2008		Nine Months Ended September 30, 2007
Depletion	$ 174,715	$	138,826
Depreciation	2,499		2,293
Accretion of asset retirement obligations	2,341		2,095
Total	$ 179,555	$	143,214

DD&A increased $36.3 million primarily due to $35.9 million in higher depletion expense between periods. Of this $35.9 million increase in depletion, $17.8 million relates to higher oil and gas volumes produced during the first nine months of 2008, while $18.1 million relates to our higher depletion rate in 2008. On a BOE basis, our DD&A rate increased from $13.02 for the first nine months of 2007 to $14.47 for the first nine months of 2008. The primary factors causing this rate increase were (i) $819.9 million in drilling expenditures incurred during the past twelve months in relation to net oil and gas reserve additions over the same time period, and (ii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

Exploration and Impairment Costs. Our exploration and impairment costs increased $4.3 million, as compared to the first nine months of 2007. The components of exploration and impairment costs were as follows (in thousands):

	Nine Months Ended September 30, 2008		Nine Months Ended September 30, 2007
Exploration	$ 21,550	$	19,081
Impairment	9,016		7,158
Total	$ 30,566	$	26,239

Exploration costs increased $2.5 million during the first nine months of 2008 as compared to the same period in 2007 primarily due to higher exploration employee compensation costs and exploratory dry hole expense, partially offset by a decrease in geological and geophysical (“G&G”) activity. Exploration compensation expenses were $3.9 million higher between periods due to an increase of $2.7 million in accrued distributions under our Production Participation Plan for exploration personnel and due to additional geological and geophysical employees hired during the past twelve months. During the first nine months of 2008, we drilled one exploratory dry hole in the Permian region totaling $1.5 million, while during the same period in 2007 we participated in a non-operated exploratory well in the Gulf Coast region that resulted in an insignificant amount of dry hole expense. G&G costs amounted to $7.6 million during the first nine months of 2008, as compared to $10.5 million during the first nine months of 2007. The impairment charge in the first nine months of 2008 and 2007 is related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of September 30, 2008, the amount of unproved properties being amortized totaled $72.2 million, as compared to $48.8 million as of September 30, 2007.

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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,	
	2008	2007
General and administrative expenses	$ 82,411	$ 52,338
Reimbursements and allocations	(30,508)	(24,397)
General and administrative expense, net	$ 51,903	$ 27,941

General and administrative expense before reimbursements and allocations increased $30.1 million to $82.4 million during the first nine months of 2008. The largest components of the increase related to (i) $21.5 million in higher accrued distributions under our Production Participation Plan between periods due to increased oil and gas sales less lease operating expense and production taxes, and (ii) $8.1 million of additional employee compensation for personnel hired during the past twelve months as well as general pay increases. The increase in reimbursements and allocations in 2008 was caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and gas sales remained constant at 5% for the first nine months of 2008 and 2007.

Change in Production Participation Plan Liability. For the nine months ended September 30, 2008, this non-cash expense increased $20.6 million as compared to the same period in 2007. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2009 under our Production Participation Plan (“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 2008 and 2007 primarily reflects (i) changes to future cash flow estimates stemming from a sustained higher commodity price environment, (ii) recent drilling activity, and (iii) employees’ continued vesting in the Plan. Due to the recent higher commodity price environment, during the nine months ended September 30, 2008 we moved from using a five-year average of historical NYMEX prices to a three-year average when estimating the future payments to be made pursuant to this liability. The average NYMEX prices used to estimate this liability increased by $20.95 for crude oil and $0.71 for natural gas for the nine months ended September 30, 2008, as compared to increases of $6.09 for crude oil and $0.53 for natural gas over the same period in 2007. 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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Interest Expense. The components of our interest expense were as follows (in thousands):

	Nine Months Ended September 30, 2008	2007
Credit agreement	$ 13,410	$ 20,035
Senior subordinated notes	32,698	33,571
Amortization of debt issue costs and debt discount	3,618	3,793
Accretion of tax sharing liability	934	1,142
Other	156	445
Capitalized interest	(2,056)	(2,472)
Total interest expense	$ 48,760	$ 56,514

The decrease in interest expense was mainly due to lower effective interest rates on our debt during the first nine months of 2008.

Our weighted average debt outstanding during the first nine months of 2008 was $1,002.6 million, while it was $996.1 million for the first nine months of 2007. Our weighted average effective cash interest rate was 6.2% during the first nine months of 2008 compared to 7.2% during the first nine months of 2007. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 6.6% during the first nine months of 2008 compared to 7.7% during the first nine months of 2007.

(Gain) Loss on Mark-to-Market Derivatives. During 2008, we entered into derivative contracts that we did not designate as cash flow hedges. Accordingly, these 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 (gain) loss on mark-to-market derivatives. As a result of increases in oil prices, we recognized $7.0 million in unrealized mark-to-market derivative losses and $0.04 million in realized cash settlement losses for the first nine months of 2008. During 2007, the forecasted transactions, to which certain crude oil collars had been designated, were no longer probable of occurring within their specified time periods. We therefore reclassified the net loss attributable to these hedges out of accumulated other comprehensive loss and recognized $1.2 million in unrealized mark-to-market derivative losses during the first nine months of 2007.

Income Tax Expense. Income tax expense totaled $148.4 million for the first nine months of 2008 and $50.6 million for the first nine months of 2007. Our effective income tax rate decreased from 37.4% for the first nine months 2007 to 36.8% for the first nine months of 2008. Our effective income tax rate was higher in 2007 due to adjustments of our tax estimates to actuals based on 2006 returns as filed.

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Net Income. Net income increased from $84.9 million during the first nine months of 2007 to $255.2 million during the first nine months of 2008. The primary reasons for this increase include a 13% increase in equivalent volumes sold, a 57% increase in oil prices (net of hedging) and a 44% increase in gas prices between periods, amortization of deferred gain on sale, and lower interest expense. These positive factors were partially offset by higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative expenses, Production Participation Plan expense, losses on mark-to-market derivatives, income taxes as well as no gain on sale of properties during the first nine months of 2008.

Three Months Ended September 30, 2008 Compared to Three Months Ended September 30, 2007

Selected Operating Data:	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007
Net production:		
Oil (MMbbls)	3.3	2.5
Natural gas (Bcf)	8.2	7.6
Total production (MMBOE)	4.6	3.7
Net sales (in millions):		
Oil (1)	$ 354.8	$ 167.4
Natural gas (1)	70.6	38.2
Total oil and natural gas sales	$ 425.4	$ 205.6
Average sales prices:		
Oil (per Bbl)	$ 108.04	$ 67.51
Effect of oil hedges on average price (per Bbl)	(12.76)	(0.85)
Oil net of hedging (per Bbl)	$ 95.28	$ 66.66
Average NYMEX price	$ 118.13	$ 75.03
Natural gas (per Mcf)	$ 8.65	$ 5.06
Effect of natural gas hedges on average price (per Mcf)	-	-
Natural gas net of hedging (per Mcf)	$ 8.65	$ 5.06
Average NYMEX price	$ 10.27	$ 6.16
Cost and expense (per BOE):		
Lease operating expenses	$ 13.93	$ 14.30
Production taxes	$ 6.08	$ 3.53
Depreciation, depletion and amortization expense	$ 15.99	$ 13.19
General and administrative expenses	$ 3.72	$ 2.88

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $219.8 million to $425.4 million in the third quarter of 2008 compared to the third quarter of 2007. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 32% between periods, while our gas sales volumes increased 8%. 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 870 Mbbl compared to the third quarter of 2007, while Postle oil production increased 100 Mbbl and North Ward Estes oil production increased 85 Mbbl over the same period in 2007. These production increases were partially offset by the Trust divestiture, which decreased oil production by 220 Mbbl. The gas volume increase between periods was primarily the result of incremental production of 1,370 MMcf added from the Flat Rock acquisition and higher production in the Boies Ranch area of 640 MMcf. These increases were partially offset by the Trust divestiture, which decreased gas production by 1,050 MMcf, as well as normal field production decline. Our average price for oil before effects of hedging increased 60% between periods, and our average price for natural gas before effects of hedging increased 71%.

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Loss on Oil Hedging Activities. We hedged 34% of our oil volumes during the third quarter of 2008, incurring cash settlement losses of $41.9 million, and 50% of our oil volumes during the third quarter of 2007, incurring cash settlement losses of $2.1 million. We hedged 2% of our gas volumes during the third quarter of 2008, incurring no cash settlement gains or losses, and we did not hedge any of our gas volumes during the third quarter of 2007. See Item 3, “Qualitative and Quantitative Disclosures About Market Risk” for a list of our outstanding oil and natural gas hedges as of October 1, 2008.

Gain on Sale of Properties. There was no gain or loss on the sale of properties during the three months ended September 30, 2008. During the three months ended September 30, 2007, however, we sold certain non-core properties for aggregate sales proceeds of $44.1 million, resulting in a pre-tax gain on sale of $29.7 million.

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

Lease Operating Expenses. Our lease operating expenses during the third quarter of 2008 were $64.7 million, an $11.2 million (21%) increase over the third quarter of 2007. Our lease operating expenses per BOE decreased from $14.30 during the third quarter of 2007 to $13.93 during the third quarter of 2008. The decrease of 3% on a BOE basis was primarily caused by flush production from Bakken drilling, partially offset by inflation in the cost of oil field goods and services and a higher level of workover activity. Workovers amounted to $9.4 million in the third quarter of 2008, as compared to $4.7 million in the third quarter of 2007.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for the third quarter of 2008 and 2007 were 6.6% and 6.4%, respectively, of oil and gas sales. Our production tax rate for the third quarter of 2008 was greater than the rate for same period in 2007 due to the change in property mix associated with recent divestitures in low tax rate jurisdictions and drilling successes in higher tax rate jurisdictions.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense increased $24.9 million as compared to the third quarter of 2007. The components of our DD&A expense were as follows (in thousands):

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	Three Months Ended September 30, 2008	2007
Depletion	$ 72,464	$ 47,777
Depreciation	905	790
Accretion of asset retirement obligations	864	741
Total	$ 74,233	$ 49,308

DD&A increased $24.9 million primarily due to $24.7 million in higher depletion expense between periods. Of the $24.7 million increase in depletion, $11.6 million is related to higher oil and gas volumes produced during the third quarter of 2008, while $13.1 million relates to our higher depletion rate in 2008. On a BOE basis, our DD&A rate increased from $13.19 for the third quarter of 2007 to $15.99 for the third quarter of 2008. The primary factors causing this rate increase were (i) $819.9 million in drilling expenditures incurred during the past twelve months in relation to net oil and gas reserve additions over the same time period, and (ii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

Exploration and Impairment Costs. Our exploration and impairment costs increased $0.5 million, as compared to the third quarter of 2007. The components of exploration and impairment costs were as follows (in thousands):

	Three Months Ended September 30, 2008	2007
Exploration	$ 7,323	$ 7,903
Impairment	3,616	2,517
Total	$ 10,939	$ 10,420

Exploration costs decreased $0.6 million for the third quarter of 2008 as compared to the same period in 2007 primarily due to a decrease in G&G activity between periods, partially offset by higher exploratory dry hole expense and exploration employee compensation costs. G&G costs amounted to $1.8 million during the three months ended September 30, 2008, as compared to $5.0 million during the same three months of 2007. During the third quarter of 2008, we drilled one exploratory dry hole in the Permian region totaling $1.5 million, while during the same period in 2007 we participated in a non-operated exploratory well in the Gulf Coast region that resulted in an insignificant amount of dry hole expense. Exploration compensation expenses were higher primarily due to an increase of $0.5 million in accrued distributions under our Production Participation Plan for exploration personnel and due to additional geological and geophysical employees hired during the past twelve months. The impairment charge in the third quarter of 2008 and 2007 is related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of September 30, 2008, the amount of unproved properties being amortized totaled $72.2 million, as compared to $48.8 million as of September 30, 2007.

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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,	
	2008	2007
General and administrative expenses	$ 28,096	$ 19,341
Reimbursements and allocations	(10,815)	(8,561)
General and administrative expense, net	$ 17,281	$ 10,780

General and administrative expense before reimbursements and allocations increased $8.8 million to $28.1 million during the third quarter of 2008. The largest components of the increase related to (i) $4.6 million in higher accrued distributions under our Production Participation Plan between periods due to increased oil and gas sales less lease operating expense and production taxes, and (ii) $3.6 million of additional employee compensation for personnel hired during the past twelve months as well as general pay increases. The increase in reimbursements and allocations in 2008 was caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and gas sales decreased from 5% for the third quarter of 2007 to 4% for the third quarter of 2008.

Change in Production Participation Plan Liability. For the three months ended September 30, 2008, this non-cash expense increased $6.9 million to $9.1 million, as compared to the same period in 2007. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2009 under our Production Participation Plan (“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 2008 and 2007 primarily reflects (i) changes to future cash flow estimates stemming from a sustained higher commodity price environment, (ii) recent drilling activity, and (iii) employees’ continued vesting in the Plan. Due to the recent higher commodity price environment, during the second quarter of 2008 we moved from using a five-year average of historical NYMEX prices to a three-year average when estimating the future payments to be made pursuant to this liability. The average NYMEX prices used to estimate this liability increased by $5.44 for crude oil and decreased by $0.03 for natural gas for the three months ended September 30, 2008, as compared to increases of $2.32 for crude oil and $0.15 for natural gas over the same period in 2007. 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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Interest Expense. The components of our interest expense were as follows (in thousands):

	Three Months Ended September 30,	
	2008	2007
Credit agreement	$ 5,757	$ 4,595
Senior subordinated notes	10,755	11,199
Amortization of debt issue costs and debt discount	1,195	1,251
Accretion of tax sharing liability	311	381
Other	47	245
Capitalized interest	(522)	(1,408)
Total interest expense	$ 17,543	$ 16,263

The increase in interest expense was mainly due to higher borrowings under our credit agreement, partially offset by lower effective interest rates on our debt during the third quarter of 2008.

Our weighted average debt outstanding during the third quarter of 2008 was $1,147.6 million, while it was $868.8 million for the third quarter of 2007. Our weighted average effective cash interest rate was 5.8% during the third quarter of 2008 compared to 7.4% during the third quarter of 2007. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 6.2% during the third quarter of 2008 compared to 7.9% during the third quarter of 2007.

(Gain) Loss on Mark-to-Market Derivatives. During 2008, we entered into derivative contracts that we did not designate as cash flow hedges. Accordingly, these 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 (gain) loss on mark-to-market derivatives. As a result of decreases in oil prices during the quarter, we recognized $10.6 million in unrealized mark-to-market derivative gains and $0.03 million in realized cash settlement losses in the third quarter of 2008. During 2007, the forecasted transactions, to which certain crude oil collars had been designated, were no longer probable of occurring within their specified time periods. Therefore, we discontinued hedge accounting prospectively for these collars and recognized $0.5 million in unrealized mark-to-market derivative gains during the third quarter of 2007.

Income Tax Expense. Income tax expense totaled $64.5 million for the third quarter of 2008 and $29.6 million for the third quarter of 2007. Our effective income tax rate decreased from 38.3% for the third quarter 2007 to 36.5% for the third quarter of 2008. Our effective income tax rate was higher in 2007 due to adjustments of our tax estimates to actuals based on 2006 returns as filed.

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Net Income. Net income increased from $47.7 million during the third quarter of 2007 to $112.4 million during the third quarter of 2008. The primary reasons for this increase include a 24% increase in equivalent volumes sold, a 43% increase in oil prices (net of hedging) and a 71% increase in gas prices between periods, amortization of deferred gain on sale and unrealized mark-to-market derivative gains. These positive factors were partially offset by higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative expenses, Production Participation Plan expense, interest expense, income taxes as well as no gain on sale of properties during the third quarter of 2008.

Liquidity and Capital Resources

Overview. At September 30, 2008, our debt to total capitalization ratio was 38.6%, we had $20.6 million of cash on hand and $1,779.4 million of stockholders' equity. At December 31, 2007, our debt to total capitalization ratio was 36.8%, we had $14.8 million of cash on hand and $1,490.8 million of stockholders' equity. In the first nine months of 2008, we generated $611.5 million of cash provided by operating activities, an increase of $338.8 million over the same period in 2007. Cash provided by operating activities increased primarily because of higher oil volumes produced in 2008 and higher average sales prices for both crude oil and natural gas. We also generated $250.0 million from financing activities consisting entirely of net borrowings against our credit agreement. Cash flows from operating and financing activities, as well as $193.8 million in net proceeds from the sale of Trust units, were used to finance $638.4 million of drilling and development expenditures paid in the first nine months of 2008 and $413.2 million of cash acquisition capital expenditures. The following chart details our exploration and development expenditures incurred by region during the first nine months of 2008 (in thousands):

	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 335,174	$ 5,389	$ 340,563	50%
Permian Basin	206,216	7,182	213,398	31%
Mid-Continent	77,775	1,582	79,357	12%
Gulf Coast	31,377	420	31,797	5%
Michigan	11,710	6,977	18,687	2%
Total incurred	662,252	21,550	683,802	100%
Increase in accrued capital expenditures	(23,852)	-	(23,852)	
Total paid	$ 638,400	$ 21,550	$ 659,950	

We continually evaluate our capital needs and compare them to our capital resources. Our current 2008 budgeted capital expenditures for the further development of our property base are $900.0 million, an increase from the $556.6 million incurred on exploration and development expenditures during 2007. We increased our 2008 exploration and development budget from $850.0 million to $900.0 million due primarily to additional exploration and development activities across our regions. In the first nine months of 2008, we spent $31.8 million on tubulars (casing, tubing and flow lines) and $381.4 million on oil and gas property acquisitions, including the Flat Rock acquisition of $359.4 million which was funded by borrowings under Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") credit agreement. Although we have no specific budget for property acquisitions in 2008, we will continue to selectively pursue property acquisitions that complement our existing core property base. We expect to fund our 2008 exploration and development expenditures from internally generated cash flow, cash on hand, and borrowings under our credit agreement. We believe that should attractive acquisition opportunities arise or exploration and development expenditures exceed $900.0 million, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, or agreements with industry partners. However, we recognize that the issuance of additional securities in periods of market volatility may be less likely. 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. Although we have not yet formally determined our 2009 exploration and development budget, we expect to set this budget at an amount that approximates estimated discretionary cash flow generated during 2009.

Credit Agreement. Whiting Oil and Gas, our wholly-owned subsidiary, has a $1.2 billion credit agreement with a syndicate of banks that, as of September 30, 2008, had a borrowing base of $900.0 million with $397.3 million of available borrowing capacity, which is net of $500.0 million in borrowings and $2.7 million in letters of credit outstanding. The borrowing base under the credit agreement is determined at the discretion of our lenders, based on the collateral value of our proved reserves that have been mortgaged to our 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.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas may, throughout the term of the credit agreement, borrow, repay and re-borrow up to the borrowing base in effect at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours in an aggregate amount not to exceed $50.0 million. As of September 30, 2008, $47.3 million was available for additional letters of credit under the agreement.

Interest accrues at Whiting Oil and Gas' option at either (1) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage and are included as a component of interest expense. At September 30, 2008, the effective weighted average interest rate on the outstanding principal balance under the credit agreement was 3.9%.

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The credit agreement contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders and requires us to maintain a debt to EBITDAX ratio (as defined in the credit agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit facility) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and our wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. We were in compliance with our covenants under the credit agreement as of September 30, 2008. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for the guarantee, and Equity Oil Company has mortgaged all of its properties, which are included in the borrowing base for the credit agreement, as security for its guarantee.

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 notes are unsecured obligations of ours and are subordinated to all of our senior debt, which currently consists of Whiting Oil and Gas' credit agreement. 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, incur additional indebtedness 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, 2008. Our wholly-owned operating subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company, have fully, unconditionally, jointly and severally guaranteed our obligations under the notes.

Shelf Registration Statement. We have on file with the SEC a universal shelf registration statement to allow us to offer an indeterminate amount of securities in the future. Under the registration statement, we may periodically offer from time to time debt securities, common stock, preferred stock, warrants and other securities or any combination of such securities in amounts, prices and on terms announced when and if the securities are offered. However, we recognize that the issuance of additional securities in periods of market volatility may be less likely. The specifics of any future offerings, along with the use of proceeds of any securities offered, will be described in detail in a prospectus supplement at the time of any such offering.

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liabilities since we cannot determine with accuracy the timing or amounts of future payments. The following table summarizes our obligations and commitments as of September 30, 2008 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

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Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	Payments due by period				
Long-term debt (a)	$ 1,120,000	$ -	$ 500,000	$ 370,000	$ 250,000
Cash interest expense on debt (b)	251,919	62,586	103,830	66,545	18,958
Asset retirement obligation (c)	43,684	1,430	716	3,561	37,977
Tax sharing liability (d)	26,591	2,587	4,408	3,699	15,897
Derivative contract liability fair value (e)	30,289	25,046	3,279	1,964	-
Purchasing obligations (f)	240,978	43,941	97,454	80,724	18,859
Drilling rig contracts (g)	177,953	82,172	82,218	13,563	-
Operating leases (h)	14,477	2,472	5,837	5,929	239
Total	$ 1,905,891	$ 220,234	$ 797,742	$ 545,985	$ 341,930

(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, 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. The interest rate swap on the $75.0 million of our $150.0 million fixed rate 7.25% Senior Subordinated Notes due 2012 is assumed to equal 5.3% until the due date of the instrument. 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 3.9%.

(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) We have entered into derivative contracts in the form of costless collars to hedge our exposure to crude oil and natural gas price fluctuations. As of September 30, 2008, the forward price curves for crude oil 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 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 a fixed fee, subject to annual escalation, 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.

(g) We currently have one drilling rig under contract through 2008, six drilling rigs through 2009, four drilling rigs through 2010, two drilling rigs through 2012 and one workover rig under contract through 2009, all of which are operating in the Rocky Mountains region. As of September 30, 2008, early termination of these contracts would have required maximum penalties of $98.4 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the 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 through October 31, 2013, and an additional 46,700 square feet of office space in Midland, Texas through March 7, 2012.

Based on current oil and 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.

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New Accounting Pronouncements

In March 2008, the FASB issued Statement No. 161, Disclosure about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133 (“SFAS 161”). The adoption of SFAS 161 is not expected to have an impact on our consolidated financial statements, other than additional disclosures. 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. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008.

In December 2007, the FASB issued Statement No. 160, Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51 (“SFAS 160”). As we currently do not have any minority interests, we do not expect the adoption of SFAS 160 to have an impact on our consolidated financial statements. This statement amends ARB No. 51 and intends to improve the relevance, comparability, and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards of the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. SFAS 160 is effective for fiscal years, and interim periods, beginning on or after December 15, 2008.

In December 2007, the FASB issued Statement No. 141R, Business Combinations (“SFAS 141R”). SFAS 141R may have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions we consummate after the effective date. SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in business combinations and determines what information to disclose to enable users of the financial statement to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008.

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, 2007.

Effects of Inflation and Pricing

We experienced increased costs during 2007 and the first nine months of 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 gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans 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 gas could result in increases in the costs of materials, services and personnel.

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Forward-Looking Statements

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

These risks and uncertainties include, but are not limited to: declines in oil or gas prices; 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 drilling rigs and CO_2; our ability to obtain external capital to finance 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; inaccuracies of our reserve estimates or our assumptions underlying them; 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; risks related to our level of indebtedness and periodic redeterminations of our borrowing base under our credit agreement; our ability to replace our oil and gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption “Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007. 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, 2007 and have not materially changed since that report was filed.

Our outstanding hedges as of October 1, 2008 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	NYMEX Floor/Ceiling
Crude Oil	10/2008 to 12/2008	110,000	$48.00/$70.20
Crude Oil	10/2008 to 12/2008	120,000	$60.00/$75.85
Crude Oil	10/2008 to 12/2008	100,000	$65.00/$81.20

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 2008 Highlights and Future Considerations and 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 2,164 Mbbls of crude oil and 8,512 MMcf of natural gas from 2008 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 Trust, we retain 10% of the net proceeds from the underlying properties. Our retention of 10% of these net proceeds combined with our ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, while we retain 24.2%, of future economic results of such hedges. No additional hedges are allowed to be placed on Trust assets.

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

Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	NYMEX Floor/Ceiling
Crude Oil	10/2008 to 12/2008	25,718	$82.00/$128.30
Crude Oil	10/2008 to 12/2008	25,718	$82.00/$134.85
Crude Oil	01/2009 to 03/2009	25,059	$76.00/$136.70
Crude Oil	01/2009 to 03/2009	25,059	$76.00/$142.99
Crude Oil	04/2009 to 06/2009	24,397	$76.00/$134.70
Crude Oil	04/2009 to 06/2009	24,397	$76.00/$140.39
Crude Oil	07/2009 to 09/2009	23,755	$76.00/$133.70
Crude Oil	07/2009 to 09/2009	23,755	$76.00/$139.12
Crude Oil	10/2009 to 12/2009	23,120	$76.00/$132.90
Crude Oil	10/2009 to 12/2009	23,120	$76.00/$138.54
Crude Oil	01/2010 to 03/2010	22,542	$76.00/$132.35
Crude Oil	01/2010 to 03/2010	22,542	$76.00/$137.82
Crude Oil	04/2010 to 06/2010	21,989	$76.00/$132.10
Crude Oil	04/2010 to 06/2010	21,989	$76.00/$137.60
Crude Oil	07/2010 to 09/2010	21,483	$76.00/$131.90

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Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	NYMEX Floor/Ceiling
Crude Oil	07/2010 to 09/2010	21,483	$76.00/$137.88
Crude Oil	10/2010 to 12/2010	20,962	$76.00/$131.90
Crude Oil	10/2010 to 12/2010	20,962	$76.00/$138.32
Crude Oil	01/2011 to 03/2011	20,489	$74.00/$136.00
Crude Oil	01/2011 to 03/2011	20,489	$74.00/$143.35
Crude Oil	04/2011 to 06/2011	20,033	$74.00/$136.20
Crude Oil	04/2011 to 06/2011	20,033	$74.00/$143.95
Crude Oil	07/2011 to 09/2011	19,585	$74.00/$136.10
Crude Oil	07/2011 to 09/2011	19,585	$74.00/$144.19
Crude Oil	10/2011 to 12/2011	19,121	$74.00/$136.55
Crude Oil	10/2011 to 12/2011	19,121	$74.00/$144.94
Crude Oil	01/2012 to 03/2012	18,706	$74.00/$136.95
Crude Oil	01/2012 to 03/2012	18,706	$74.00/$145.59
Crude Oil	04/2012 to 06/2012	18,286	$74.00/$137.30
Crude Oil	04/2012 to 06/2012	18,286	$74.00/$146.15
Crude Oil	07/2012 to 09/2012	17,871	$74.00/$137.30
Crude Oil	07/2012 to 09/2012	17,871	$74.00/$146.09
Crude Oil	10/2012 to 12/2012	17,514	$74.00/$137.80
Crude Oil	10/2012 to 12/2012	17,514	$74.00/$146.62
Natural Gas	10/2008 to 12/2008	228,830	$7.00/$19.00
Natural Gas	01/2009 to 03/2009	216,333	$7.00/$22.50
Natural Gas	04/2009 to 06/2009	201,263	$6.00/$14.85
Natural Gas	07/2009 to 09/2009	192,870	$6.00/$15.60
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 2008 crude oil contracts listed in both tables above, a hypothetical $1.00 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in our gain (loss) on hedging activities in 2008 of $1.1 million. For the 2008 natural gas contracts listed above, a hypothetical $0.10 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in our gain (loss) on hedging activities in 2008 of $0.07 million.

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In a 1997 non-operated property acquisition, we became subject to the operator's fixed price gas sales contract with end users for a portion of the natural gas we produce in Michigan. This contract has built-in pricing escalators of 4% per year. Our estimated future production volumes to be sold under the fixed pricing terms of this contract as of October 1, 2008 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	2008 Price Per MMBtu
Natural Gas	10/2008 to 05/2011	24,000	$4.94
Natural Gas	10/2008 to 09/2012	67,000	$4.38

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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 Vice President and 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, 2008. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Vice President and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of September 30, 2008 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms, 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, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2007. No material change to such risk factors has occurred during the nine months ended September 30, 2008.

Item 5. Other Information

Entry into a Material Definitive Agreement. On October 28, 2008, Whiting's Board of Directors approved a form of indemnification agreement to be entered into by Whiting and each of Whiting's directors and executive officers. Whiting expects its directors and executive officers will execute indemnification agreements substantially in the form approved. The indemnification agreements do not increase the extent or scope of indemnification provided to Whiting's directors and executive officers under Whiting's Certificate of Incorporation and By-laws, which provide for indemnification to the fullest extent permitted by law. The indemnification agreements set forth indemnification and expense advancement rights and establish processes and procedures determining entitlement to and obtaining indemnification and advancement of expenses.

The foregoing description is not complete and is qualified in its entirety by reference to the form of indemnification agreement, a copy of which is filed as Exhibit 10.1 to this Quarterly Report on Form 10-Q and incorporated by reference herein.

Amendments to Articles of Incorporation or Bylaws; Change in Fiscal Year. On October 28, 2008, Whiting's Board of Directors adopted Amended and Restated By-laws (the "By-laws"). The By-laws effect the following amendments:

- Article II, Section 14 was amended to (i) clarify the applicability of the advance notice provisions to all stockholder proposals not properly brought under Rule 14a-8 of the Securities Exchange Act of 1934, (ii) modify the time frames necessary for such proposals to be timely and (iii) clarify the information that must be included in the written notice to the Secretary, including a new requirement that proposing stockholders disclosure certain details about the nature of their ownership interests in Whiting and related arrangements;

- Article II, Section 14 was also amended to (i) clarify the applicability of the advance notice provisions to stockholder nominations of directors, (ii) modify the time frames necessary for such nominations to be timely and (iii) clarify the information that must be included in the written notice to the Secretary, including a new requirement that nominating stockholders disclosure certain details about the nature of their ownership interests in Whiting and related arrangements; and

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- Article VIII was amended to make clear that indemnification and advancement of expense provisions constitute a contract between Whiting and each director or officer.

A stockholder who intends to present business or nominate persons for election as directors at Whiting's 2009 annual meeting of stockholders otherwise than pursuant to Rule 14a-8 under the Securities Exchange Act of 1934 (i.e., proposals stockholders intend to present at the 2009 annual meeting but do not intend to include in our proxy statement for such meeting) must comply with the requirements set forth in the By-laws. As a result of the amendments noted above, among other things, to bring business before or nominate persons for election as directors at an annual meeting, a stockholder must give written notice thereof, complying with the By-laws, to Whiting's Corporate Secretary no earlier than the 120th day and no later than the 90th day prior to the first anniversary of the preceding year's annual meeting. Under the By-laws, if Whiting does not receive notice of a stockholder proposal or nomination submitted otherwise than pursuant to Rule 14a-8 under the Securities Exchange Act of 1934 during the time period between January 6, 2009 and February 5, 2009, then the notice will be considered untimely and Whiting will not be required to present such proposal at the 2009 annual meeting.

The foregoing description is not complete and qualified in its entirety by reference to a copy of the Amended and Restated By-laws of Whiting Petroleum Corporation which is filed as Exhibit 3.1 to this Quarterly Report on Form 10-Q and incorporated by reference herein.

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 30th day of October, 2008.

WHITING PETROLEUM CORPORATION

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

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

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

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(3.1)	Amended and Restated By-laws of Whiting Petroleum Corporation, effective October 28, 2008.
(10.1)	Form of Indemnification Agreement for directors and officers of Whiting Petroleum Corporation, effective October 28, 2008.
(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.