WHITING PETROLEUM CORP
Form 10-Q
October 31, 2007

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, 2007**

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, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer T Accelerated filer £ Non-accelerated filer £

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, 2007: 42,481,679 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 operating subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain crude oil and natural gas terms used in this report:

"3-D seismic" Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

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

"Bbl/d" One Bbl per day.

"Bcf" One billion cubic feet of natural gas.

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

"BOE/d" One BOE per day.

"CO_2 flood" A tertiary recovery method in which CO_2 is injected into the reservoir to enhance oil recovery.

"completion" The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"MBOE" One thousand BOE.

"MBOE/d" One thousand BOE per day.

"Mcf" One thousand cubic feet of natural gas.

"Mcf/d" One Mcf per day.

"MMbbl" One million barrels of oil or other liquid hydrocarbons.

"MMBOE" One million BOE.

"MMbtu" One million British Thermal Units.

"MMcf/d" One million cubic feet per day.

"plugging and abandonment" Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

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"*reservoir*" A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"*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 and operations and all risks in connection therewith.

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PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements (Unaudited)

WHITING PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)
(In thousands)

	September 30, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 8,705	$ 10,372
Accounts receivable trade, net	95,240	97,831
Deferred income taxes	10,284	3,025
Prepaid expenses and other	6,982	10,484
Total current assets	121,211	121,712
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	3,161,900	2,828,282
Unproved properties	56,825	55,297
Other property and equipment	38,062	44,902
Total property and equipment	3,256,787	2,928,481
Less accumulated depreciation, depletion and amortization	(596,601)	(495,820)
Total property and equipment, net	2,660,186	2,432,661
DEBT ISSUANCE COSTS	16,022	19,352
OTHER LONG-TERM ASSETS	13,625	11,678
TOTAL	$ 2,811,044	$ 2,585,403

See notes to condensed consolidated financial statements.

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

	September 30, 2007	December 31, 2006
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 17,623	$ 21,077
Accrued liabilities	66,702	58,504
Accrued interest	24,237	9,124
Oil and gas sales payable	19,676	19,064
Accrued employee compensation and benefits	15,115	17,800
Production taxes payable	14,558	9,820
Current portion of tax sharing liability	3,565	3,565
Current portion of derivative liability	23,959	4,088
Total current liabilities	185,435	143,042
NON-CURRENT LIABILITIES:		
Long-term debt	836,663	995,396
Asset retirement obligations	40,318	36,982
Production Participation Plan liability	31,847	25,443
Tax sharing liability	24,749	23,607
Deferred income taxes	210,894	165,031
Long-term derivative liability	4,548	5,248
Other long-term liabilities	3,644	3,984
Total non-current liabilities	1,152,663	1,255,691
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $0.001 par value; 75,000,000 shares authorized, 42,481,679 and 36,947,681 shares issued and outstanding as of September 30, 2007 and December 31, 2006, respectively	42	37
Additional paid-in capital	967,907	754,788
Accumulated other comprehensive loss	(17,277)	(5,902)
Retained earnings	522,274	437,747
Total stockholders' equity	1,472,946	1,186,670
TOTAL	$ 2,811,044	$ 2,585,403

See notes to condensed consolidated financial statements.

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 205,594	$ 207,752	$ 557,953	$ 601,259
Loss on oil and natural gas hedging activities	(2,101)	(375)	(2,101)	(9,859)
Gain on sale of properties	29,682	-	29,682	-
Interest income and other	353	210	821	836
Total revenues and other income	233,528	207,587	586,355	592,236
COSTS AND EXPENSES:				
Lease operating	53,472	46,183	154,512	135,236
Production taxes	13,197	12,492	34,888	36,819
Depreciation, depletion and amortization	49,308	42,737	143,214	116,947
Exploration and impairment	10,420	6,647	26,239	22,903
General and administrative	10,780	10,035	27,941	29,285
Change in Production Participation Plan liability	2,254	1,799	6,404	5,942
Interest expense	16,263	18,879	56,514	54,479
Unrealized derivative loss	487	-	1,178	-
Total costs and expenses	156,181	138,772	450,890	401,611
INCOME BEFORE INCOME TAXES	77,347	68,815	135,465	190,625
INCOME TAX EXPENSE:				
Current	3,401	(4,075)	5,542	537
Deferred	26,233	23,346	45,073	61,674
Total income tax expense	29,634	19,271	50,615	62,211
NET INCOME	$ 47,713	$ 49,544	$ 84,850	$ 128,414
NET INCOME PER COMMON SHARE, BASIC	$ 1.14	$ 1.35	$ 2.20	$ 3.50
NET INCOME PER COMMON SHARE, DILUTED	$ 1.13	$ 1.35	$ 2.19	$ 3.49
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	42,027	36,751	38,555	36,742
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	42,152	36,838	38,728	36,810

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, 2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 84,850	$ 128,414
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	143,214	116,947
Deferred income taxes	45,073	61,674
Amortization of debt issuance costs and debt discount	3,793	3,922
Accretion of tax sharing liability	1,142	1,549
Stock-based compensation	3,652	2,915
Gain on sale of properties	(29,682)	-
Unproved leasehold impairments	7,158	1,742
Change in Production Participation Plan liability	6,404	5,942
Unrealized derivative loss	1,178	-
Other non-current	(3,596)	(1,887)
Changes in current assets and liabilities:		
Accounts receivable trade	2,591	9,642
Prepaid expenses and other	3,654	(7,132)
Accounts payable and accrued liabilities	(13,301)	10,902
Accrued interest	15,113	8,615
Other current liabilities	1,366	8,635
Net cash provided by operating activities	272,609	351,880
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(16,780)	(79,169)
Drilling and development capital expenditures	(353,686)	(349,523)
Proceeds from sale of oil and gas properties	45,419	-
Net cash used in investing activities	(325,047)	(428,692)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	210,394	-
Long-term borrowings under credit agreement	274,400	255,000
Repayments of long-term borrowings under credit agreement	(434,400)	(185,000)
Debt issuance costs	-	(103)
Tax effect from restricted stock vesting	377	283
Net cash provided by financing activities	50,771	70,180
NET CHANGE IN CASH AND CASH EQUIVALENTS	(1,667)	(6,632)
CASH AND CASH EQUIVALENTS:		
Beginning of period	10,372	10,382

End of period	$	8,705	$	3,750
SUPPLEMENTAL CASH FLOW DISCLOSURES:				
Cash paid for income taxes	$	1,717	$	2,493
Cash paid for interest	$	38,938	$	40,697
NONCASH INVESTING ACTIVITIES:				
(Increase) decrease in accrued capital expenditures	$	(17,973)	$	7,824

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	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Retained Earnings	Total Stockholders' Equity	Comprehensive Income
BALANCES—January 1, 2006	36,842	$ 37	$ 753,093	$ (34,620)	$ (2,031)	$ 281,383	$ 997,862	
Net income	-	-	-	-	-	156,364	156,364	$ 156,364
Change in derivative fair values, net of taxes of $15,409	-	-	-	24,140	-	-	24,140	24,140
Realized loss on settled derivative contracts, net of taxes of $2,923	-	-	-	4,578	-	-	4,578	4,578
Restricted stock issued	126	-	-	-	-	-	-	-
Restricted stock forfeited	(10)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(10)	-	(440)	-	-	-	(440)	-
Tax effect from restricted stock vesting	-	-	288	-	-	-	288	-
Adoption of SFAS 123R	-	-	(2,122)	-	2,031	-	(91)	-
Stock-based compensation	-	-	3,969	-	-	-	3,969	-
BALANCES—December 31, 2006	36,948	37	754,788	(5,902)	-	437,747	1,186,670	$ 185,082
Net income	-	-	-	-	-	84,850	84,850	84,850
Change in derivative fair values, net of taxes of $7,389	-	-	-	(13,409)	-	-	(13,409)	(13,409)
Realized loss on settled derivative contracts, net of taxes of $771	-	-	-	1,330	-	-	1,330	1,330
Non-qualifying derivative loss, net of taxes of $410	-	-	-	704	-	-	704	704
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	(29)	-	(1,299)	-	-	-	(1,299)	-
Tax effect from restricted stock vesting	-	-	377	-	-	-	377	-
Stock-based compensation	-	-	3,652	-	-	-	3,652	-
Adoption of FIN 48	-	-	-	-	-	(323)	(323)	-
	42,482	$ 42	$ 967,907	$ (17,277)	$ -	$ 522,274	$ 1,472,946	$ 73,475

BALANCES—September 30, 2007

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 and its consolidated subsidiaries, all of which are wholly owned. 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 2006 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 consolidated financial statements included in Whiting's 2006 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 and other dilutive securities outstanding. The only securities considered dilutive are the Company's unvested restricted stock awards.

Change in Accounting Principle—In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an interpretation of Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* ("FIN 48"). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

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The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the Company recognized a $0.3 million increase in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings and a corresponding increase in other long-term liabilities. As of the adoption date and after the impact of recognizing the increase in liability noted above, the Company's unrecognized tax benefits totaled $0.4 million. The Company's unrecognized tax benefits related to EOR credits increased by $0.1 million. Included in the unrecognized tax benefit balance at September 30, 2007, are $0.2 million of tax positions, the allowance of which would positively affect the annual effective income tax rate. At September 30, 2007, it was reasonably possible that unrecognized tax benefits in the amount of $0.3 million relating to gas imbalances would decrease within the next 12 months, as Whiting had applied for a change in the method of accounting to a method prescribed by the Internal Revenue Service ("IRS"). In October 2007, the Company received notification from the IRS that the change in accounting had been approved. The related decrease to unrecognized tax benefits will be reflected in the Company's financial statements for the quarter ended December 31, 2007.

The Company files income tax returns in the U.S. Federal jurisdiction, in various states, and previously filed in two foreign jurisdictions. The following is a listing of tax years that remain subject to examination by major jurisdiction:

U.S. Federal	12/31/2004 – 12/31/2006
U.S. states	12/31/2004 – 12/31/2006
Canada	01/01/2002 – 12/31/2006
Province of Alberta	01/01/2002 – 12/31/2006

Prior to November 23, 2003, Whiting was owned 100% by Alliant Energy Corporation ("Alliant Energy"). Alliant Energy is presently under audit by the IRS for the years 1999 through 2003. Based on discussions with Alliant Energy, the Company believes that there are no issues that would require adjustment to Whiting's tax liability for the periods 1999 to 2001. Information is not yet available for the 2002 to 2003 periods.

The Company's policy is to recognize potential interest and penalties accrued related to unrecognized tax benefits within income tax expense. For the nine months ended September 30, 2007, the Company did not recognize any interest or penalties in the condensed consolidated statements of income, nor did the Company have any interest or penalties accrued in its condensed consolidated balance sheet at September 30, 2007 relating to unrecognized tax benefits.

2. ACQUISITIONS AND DIVESTITURES

2007 Acquisitions

There were no significant acquisitions during the first nine months of 2007.

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, adjusted to the July 1, 2007 divestiture effective date, thereby yielding a sale price of $17.77 per BOE. The June 2007 average daily net production from these fields was 760 BOE/d.

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During 2007, the Company sold its interests in several additional non-core properties for an aggregate amount of $5.3 million in cash. The divested properties are located in Colorado, Louisiana, Michigan, Oklahoma and Texas. The average daily net production from the divested property interests was 156 BOE/d as of the dates of disposition.

2006 Acquisitions

Utah Hingeline—On August 29, 2006, the Company acquired a 15% working interest in approximately 170,000 acres of unproved properties in the central Utah Hingeline play for $25.0 million. No producing properties or proved reserves were associated with this acquisition. As part of this transaction, the operator agreed to pay 100% of the Company’s drilling and completion costs for the first three wells in the project. The first of these three wells was drilled in the fourth quarter of 2006 but did not find commercial quantities of hydrocarbons. With respect to the remaining two wells, the operator began drilling one in October 2007, and the other is planned to be drilled before the end of 2008.

Michigan Properties—On August 15, 2006, the Company acquired 65 producing properties, a gathering line, gas processing plant and 30,437 net acres of leasehold held by production in Michigan. The purchase price was $26.0 million for estimated proved reserves of 1.4 MMBOE as of the acquisition effective date of May 1, 2006, resulting in a cost of $18.55 per BOE of estimated proved reserves. Proved developed reserve quantities represented 99% of the total proved reserves acquired. The average daily net production from the properties was 0.6 MBOE/d as of the acquisition effective date. The Company operates 85% of the properties acquired.

The Company funded its 2006 acquisitions with cash on hand as well as through borrowings under its credit agreement.

2006 Divestitures

During 2006, the Company sold its interests in several non-core properties for an aggregate amount of $24.4 million in cash, which consisted of total estimated proved reserves of 1.4 MMBOE as of the divestitures’ effective dates. The divested properties included interests in the Cessford field in Alberta, Canada; Permian Basin of West Texas and New Mexico; and the Ashley Valley field in Uintah County, Utah. The average daily net production from the divested property interests was 0.4 MBOE/d as of the dates of disposition, and the Company recognized a pre-tax gain of $12.1 million in the fourth quarter of 2006 on the sale of these properties.

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3. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2007 and December 31, 2006 (in thousands):

	September 30, 2007	December 31, 2006
Credit Agreement	$ 220,000	$ 380,000
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $2,077 and $2,424, respectively	217,923	217,576
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $573 and $687, respectively	148,740	147,820
Total debt	$ 836,663	$ 995,396

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, 2007, had a borrowing base of $875.0 million. 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. As of September 30, 2007, the outstanding principal balance under the credit agreement was $220.0 million. In October 2007, the syndicate of banks approved an increase in the borrowing base under the credit agreement to $900.0 million, effective November 1, 2007.

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, 2007, letters of credit totaling $0.2 million were outstanding under the credit 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. Whiting Oil and Gas has consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. 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, 2007, weighted average interest rate on the outstanding principal balance under the credit agreement was 6.4%.

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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) 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, 2007. 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 $250.0 million of 7% Senior Subordinated Notes due 2014 at par. The estimated fair value of these notes was $238.4 million as of September 30, 2007.

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 7.5%. The estimated fair value of these notes was $213.1 million as of September 30, 2007.

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 7.4%. The estimated fair value of these notes was $146.8 million as of September 30, 2007.

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, 2007. Three of 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.

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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, 2007, the Company has recorded a long-term liability of $0.7 million related to the interest rate swap, which has been designated as a fair value hedge, with an offsetting reduction in 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 following table provides a reconciliation of the Company's asset retirement obligations for the nine months ended September 30, 2007 (in thousands):

Asset retirement obligation, January 1, 2007	$ 37,534
Additional liability incurred	1,303
Revisions in estimated cash flows	3,473
Accretion expense	2,095
Obligations on sold properties	(1,675)
Liabilities settled	(1,788)
Asset retirement obligation, September 30, 2007	$ 40,942

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5. DERIVATIVE FINANCIAL INSTRUMENTS

Whiting enters into derivative contracts, primarily costless collars, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. 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. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not enter into derivative instruments for speculative or trading purposes.

At September 30, 2007, accumulated other comprehensive loss consisted of $27.3 million ($17.3 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, 2007, Whiting recognized realized cash settlement losses of $2.1 million on commodity derivative settlements. For the three and nine months ended September 30, 2006, Whiting recognized realized cash settlement gains of $0.4 million and realized cash settlement losses of $9.9 million, respectively, on commodity derivative settlements. Based on the estimated fair value of the Company's derivative contracts at September 30, 2007, it expects to reclassify net losses of $22.8 million into earnings related to derivative contracts during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially. The Company has hedged 1.2 MMbbl of crude oil volumes through 2007 and an additional 4.0 MMbbl of crude oil volumes in 2008.

During the first quarter of 2007, the Company determined that the forecasted transactions, to which certain crude oil collars had been designated, were no longer probable of occurring within their specified time periods from April to December of 2007. The Company therefore reclassified the cumulative net losses attributable to these hedges out of accumulated other comprehensive loss and recognized $1.1 million in unrealized derivative losses in the condensed consolidated statements of income in the first quarter of 2007. Subsequent to the first quarter of 2007, Whiting recognized an additional $0.1 million in unrealized mark-to-market losses on non-qualifying derivatives. The Company has discontinued hedge accounting prospectively for these collars.

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

6. STOCKHOLDERS' EQUITY

***Common Stock Offering* -** On July 3, 2007, the Company completed a public offering of its common stock under its existing shelf registration statement, selling 5,000,000 shares of common stock at a price of $40.50 per share, providing net proceeds of $193.9 million. Pursuant to the exercise of the underwriters' overallotment option, the Company sold an additional 425,000 shares of common stock on July 11, 2007, at $40.50 per share, providing net proceeds of $16.5 million. The Company used the net proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement.

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***Equity Incentive Plan*—**The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive 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. In February 2007, however, restricted stock awards granted to executive officers 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 restricted stock grants to executives.

The following table shows a summary of the Company's nonvested restricted stock as of September 30, 2007 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, 2007	203,264	$ 39.33
Granted	149,740	$ 45.18
Vested	(96,787)	$ 35.77
Forfeited	(11,994)	$ 44.24
Restricted stock awards nonvested, September 30, 2007	244,223	$ 44.08

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, 2007, there was $4.6 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 1.8 years. Included within general and administrative and exploration expenses is non-cash stock based compensation related to restricted stock awards of $3.7 million and $2.9 million for the nine months ended September 30, 2007 and 2006, respectively, and $1.3 million and $1.1 million for the three months ended September 30, 2007 and 2006, respectively.

***Rights Agreement* -** On February 23, 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.

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7. 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, 2007 and 2006 amounted to $11.3 million and $10.2 million, respectively, charged to general and administrative expense and $1.8 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 65, regardless of when their interests would otherwise vest; and (3) any forfeitures for Plan years after 2003 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, 2007, the Company used five-year average historical NYMEX prices of $52.29 for crude oil and $6.51 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, 2007, 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 $89.6 million. This amount includes $13.5 million attributable to proved undeveloped oil and gas properties and $13.1 million relating to the short-term portion of the Production Participation Plan liability, which has been accrued as a current payable for 2007 plan-year payments owed to employees. 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, 2007 (in thousands):

Production Participation Plan liability, January 1, 2007	$	25,443
Change in liability for accretion, vesting and change in estimates		19,541
Reduction in liability for cash payments accrued and recognized as compensation expense		(13,137)
Production Participation Plan liability, September 30, 2007	$	31,847

The Company records the expense associated with changes in the present value of estimated non-current 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 non-current portion of the liability if the Company did allocate the adjustment to these specific line items (in thousands).

	Nine Months Ended September 30,			
		2007		**2006**
General and administrative expense	$	5,499	$	5,069
Exploration expense		905		873
Total	$	6,404	$	5,942

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. Employer contributions vest ratably at 20% per year over a five year period.

8. RELATED PARTY TRANSACTIONS

Prior to Whiting's initial public offering in November 2003, it was a wholly owned indirect subsidiary of 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 not a related party.

Tax Sharing Liability - 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 $38.6 million on an undiscounted basis, with a present value of $27.1 million.

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During the first nine months of 2007, the Company did not make any payments under this agreement but did recognize $1.1 million of accretion expense, which is included as a component of interest expense. The Company's estimated payment of $3.6 million to be made in 2007 under this agreement is reflected as a current liability at September 30, 2007.

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.

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.

Receivable from Alliant Energy—Prior to the Company's initial public offering, the Company was included in the consolidated federal income tax return of Alliant Energy and calculated its income tax expense on a separate return basis at Alliant Energy's effective tax rate less any research or Section 29 tax credits generated by the Company. Current tax due under this calculation was paid to Alliant Energy, and current refunds were received from Alliant Energy. Section 29 tax credits were generated in 2002 and were utilized by Alliant Energy in 2007. On a stand-alone basis Whiting would have been unable to use the credits in its 2002 tax return. During the third quarter of 2007, the Company received payment in full from Alliant Energy on its current receivable of $4.1 million for these credits.

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

9. COMMITMENTS AND CONTINGENCIES

Non-cancelable Leases—The Company leases 87,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2010 and an additional 30,100 square feet of office space in Midland, Texas through February 15, 2012. Rental expense for the first nine months of 2007 and 2006 was $1.6 million and $1.5 million, respectively.

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Minimum lease payments under the terms of non-cancelable operating leases as of September 30, 2007 are as follows (in thousands):

2007	$ 498
2008	2,003
2009	2,017
2010	1,753
2011	381
Thereafter	48
Total	$ 6,700

***Purchase Contract*—**The Company has 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, 2007, future commitments under the purchase agreements amounted to $295.3 million through 2014.

***Drilling Contracts*—**The Company has two drilling rigs under contract through 2008, one drilling rig through 2009 and one drilling rig through 2010, in addition to a workover rig under contract through 2009, all of which are operating in the Rocky Mountains region. As of September 30, 2007, these agreements had total commitments of $56.1 million and early termination would require maximum penalties of $41.2 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.

10. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* ("SFAS 157"). The adoption of SFAS 157 is not expected to have a material impact on the Company's consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop certain fair value measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years.

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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. Under SFAS 159, a company may elect to use fair value to measure many financial instruments and certain other assets and liabilities at fair value. The Company decided not to elect fair value accounting for any of its eligible items. The adoption of SFAS 159 therefore will have no impact on Whiting's financial position, cash flows or results of operations. If the use of fair value is elected (the fair value option), 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. At the adoption date, unrealized gains and losses on existing items for which fair value has been elected are reported as a cumulative adjustment to beginning retained earnings. Subsequent to the adoption of SFAS 159, changes in fair value are recognized in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007.

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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 operating subsidiaries, Whiting Oil and Gas Corporation, Equity Oil Company and Whiting Programs. 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. During 2004 and 2005, we emphasized the acquisition of properties that provided additional volumes to our current production levels as well as upside potential through further development. During 2006 and the first nine months of 2007, 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.

While historically we have grown through acquisitions, we are increasingly focused on a balanced exploration and development program while selectively pursuing acquisitions. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows;
- seeking property acquisitions that complement our core areas; and
- allocating an increasing percentage of our capital budget to leasing and testing new areas with exploratory wells.

We have historically acquired operated and non-operated properties that meet or 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 sale 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 oil or gas could materially and adversely affect our financial position, results of operations, cash flows, access to capital, and the quantities of oil and gas reserves that we can economically produce.

Third Quarter 2007 Highlights and Future Considerations

On July 3, 2007, we completed a public offering of 5,000,000 shares of our common stock at a price of $40.50 per share, providing net proceeds of $193.9 million. Pursuant to the exercise of the underwriters' overallotment option, we sold an additional 425,000 shares of common stock on July 11, 2007, also at $40.50 per share, providing net proceeds of $16.5 million. We used the net proceeds to repay a portion of the debt outstanding under our credit agreement, thereby increasing the borrowing capacity available under the credit agreement.

On July 17, 2007, we sold our 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, adjusted to the July 1, 2007 divestiture effective date, resulting in a sale price of $17.77 per BOE. Our June 2007 average daily net production from these fields was 760 BOE/d. We used the net proceeds to repay a portion of the debt outstanding under our credit agreement.

During the third quarter of 2007, we sold our interests in several additional non-core properties for an aggregate amount of $4.1 million in cash. The divested properties are located in Louisiana, Michigan, Oklahoma and Texas. The average daily net production from the divested property interests was 123 BOE/d as of the dates of disposition. We used the net proceeds from these asset sales to fund drilling.

We continue to have significant development and related infrastructure activity on the Postle and North Ward Estes fields acquired in 2005, which has resulted in reserve and production increases. During the first nine months of 2007, we incurred $203.0 million of exploration and development expenditures on these two projects, and we expect to allocate an additional $60.0 million to these two projects for the remainder of 2007.

Our expansion of the CO_2 flood at the Postle field, located in Texas County, Oklahoma, is generating positive results. In October, average net production from the field increased to approximately 5,600 BOE/d. This compares to the field's average net production of 5,300 BOE/d in May 2007. We are currently injecting approximately 112 MMcf/d of CO_2 into the field's producing reservoir, the Morrow formation, at a depth of approximately 6,100 feet.

On May 22, 2007, we initiated our CO_2 flood in the North Ward Estes field, located in Ward and Winkler Counties, Texas. We are currently injecting approximately 14 MMcf/d of CO_2 into the Yates formation, the field's producing reservoir, at a depth of approximately 2,600 feet. Our target for CO_2 injection into the field is 100 MMcf/d by the end of the first quarter of 2008. We expect an initial response from this CO_2 flood during the second half of 2008. Net production from North Ward Estes in October has been averaging approximately 5,150 BOE/d.

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We are currently drilling two horizontal wells on our Robinson Lake prospect in Mountrail County, North Dakota. Both wells will target the Middle Bakken formation at a depth of approximately 9,900 feet. We hold an average working interest of 93% and an average net revenue interest of 74% in the two new wells. Production test results are expected from both wells before year end.

Our discovery well on the Robinson Lake prospect, the Peery State 11-25H, was completed in May 2007 in the Middle Bakken formation with an initial flow rate of 1,081 Bbl/d of oil and 1.0 MMcf/d of gas. The current flow rate is 300 Bbl/d of oil and 300 Mcf/d of gas. The triple-lateral well drilled approximately 21,000 feet of horizontal well bore. We hold a 99% working interest (80% net revenue interest) in the discovery well and are the operator.

Our Robinson Lake prospect encompasses 118,000 gross (81,000 net) acres, on which we plan to drill 18 Middle Bakken wells during the next 26 months. We currently have one drilling rig and one large workover rig working full time at Robinson Lake and plan to add a second drilling rig in January 2008 and a third drilling rig by the end of the first quarter of 2008. The workover rig is being used to drill the lateral sections of the wells.

Immediately east of the Robinson Lake prospect is the Parshall field. We own 66,000 gross (14,000 net) acres in the Parshall field, where we have participated in 22 wells. The initial 11 wells were completed between June 2006 and September 2007 and had average initial production rates of approximately 1,324 BOE/d per well. Seven wells are currently undergoing completion operations while another four are currently being drilled. We hold an average 20% working interest in the non-operated Parshall field. An additional eight wells are currently budgeted to be drilled in Parshall field during the remainder of 2007. In addition, we are drilling a 100% working interest well in the northeast portion of Parshall field.

During the third quarter, we moved two rigs into the Piceance Basin to drill Williams Fork and Iles wells on our Boies Ranch and Jimmy Gulch properties in Rio Blanco County, Colorado. Each rig has drilled one well at Boies Ranch to a total depth of approximately 11,500 feet. These two wells are currently awaiting completion operations and two additional wells are currently being drilled. Drilling operations are expected to commence at Jimmy Gulch in the first quarter of 2008. We are drilling groups of four to eight wells off of pads, with each rig moving to the next well off the same pad. Across our Boies Ranch and Jimmy Gulch Prospects, our ownership ranges from 50% to 100% working interests and 49% to 89% net revenue interests. We hold a 100% working interest and an average net revenue interest of 86% in the two new Boies Ranch wells that have reached total depth. In the two wells that are being drilled, we own a 100% working interest and an average net revenue interest of 89%.

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In the first half of 2007, we drilled and completed three gas producers at Boies Ranch, with each well flowing at an initial rate of approximately 2.3 MMcf/d of gas from the Williams Fork and Iles formations. Production from these three wells was shut in for most of the third quarter and most of October as repairs were made to a nearby gas processing plant where Boies Ranch gas had been transported. Production is expected to resume from the Boies Ranch area in November at a restricted gross rate of approximately 3.0 MMcf/d of gas (1.5 MMcf/d of gas net to the Company's interests). The three productive wells at Boies Ranch are capable of producing at a combined gross rate of 4.8 MMcf/d of gas. We plan to drill a total of 106 wells on our Boies Ranch and nearby Jimmy Gulch areas through 2009. The wells are scheduled to be drilled on 20-acre spacing units. We plan to have a minimum of two drilling rigs running full time in the Piceance Basin through 2008.

We are evaluating and engaged in discussions with respect to the potential sale of economic interests in other non-core properties, although we have not made a decision on whether to do so or the form that any such transaction would take. Our intention is to monetize the value of some of our predominantly proved developed producing properties with this potential sale. These property interests had estimated reserves of up to 8.1 MMBOE, as of an October 1, 2007 effective date. All properties being considered for potential disposition represent up to 3.5% of our proved reserves as of December 31, 2006 and 11.1%, or 4,500 BOE/d, of our September 2007 average daily net production. We expect to use the net proceeds from these asset sales to repay a portion of the debt outstanding under our credit agreement. We cannot provide any assurance, however, that we will be able to complete these asset sales.

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Results of Operations

Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Selected Operating Data:	Nine Months Ended September 30, 2007	2006
Net production:		
Oil (MMbls)	7.1	7.3
Natural gas (Bcf)	23.3	24.1
Total production (MMBOE)	11.0	11.4
Net sales (in millions):		
Oil(1)	$ 414.8	$ 436.5
Natural gas(1)	143.2	164.8
Total oil and natural gas sales	$ 558.0	$ 601.3
Average sales prices:		
Oil (per Bbl)	$ 58.37	$ 59.52
Effect of oil hedges on average price (per Bbl)	(0.29)	(1.28)
Oil net of hedging (per Bbl)	$ 58.08	$ 58.24
Average NYMEX price	$ 66.12	$ 68.29
Natural gas (per Mcf)	$ 6.14	$ 6.83
Effect of natural gas hedges on average price (per Mcf)	-	(0.02)
Natural gas net of hedging (per Mcf)	$ 6.14	$ 6.81
Average NYMEX price	$ 6.83	$ 7.46
Cost and expense (per BOE):		
Lease operating expenses	$ 14.05	$ 11.91
Production taxes	$ 3.17	$ 3.24
Depreciation, depletion and amortization expense	$ 13.02	$ 10.30
General and administrative expenses	$ 2.54	$ 2.58

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $43.3 million to $558.0 million in the first nine months of 2007 compared to the first nine months of 2006. Sales are a function of volumes sold and average sales prices. Our oil sales and gas sales volumes decreased 3% between periods**.** The volume declines resulted in part from property sales, production shut-ins due to a fire at a third-party refinery, and normal field production decline, which factors were offset by production increases from development activities. The property sales account for a decline of approximately 65 MBOE, 72% of which related to natural gas. As a result of the refinery fire, approximately 34 MBOE of production from the Postle field was shut-in or restricted from February 19 through March 8, 2007. In addition during the first nine months of 2007, we converted several production wells to injectors at our North Ward Estes field, as the reservoir was pressured up in the Phase 1 area in preparation for CO_2 injection. Our average price for oil before effects of hedging decreased 2% and our average price for natural gas before effects of hedging decreased 10% between periods.

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Loss on Oil and Natural Gas Hedging Activities. We hedged 54% of our oil volumes during the first nine months of 2007, incurring derivative settlement losses of $2.1 million, and 54% of our oil volumes during the first nine months of 2006, incurring derivative settlement losses of $9.4 million. We hedged 21% of our gas volumes during the first nine months of 2007, incurring no realized hedging gains or losses and 58% of our gas volumes during the first nine months of 2006, incurring derivative settlement losses of $0.5 million. See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil hedges as of October 1, 2007.

Gain on sale of properties. During the nine months ended September 30, 2007, 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. There was no gain on sale of properties during the nine months ended September 30, 2006.

Lease Operating Expenses. Our lease operating expenses increased $19.3 million to $154.5 million in the first nine months of 2007 compared to the first nine months of 2006. Our lease operating expense as a percentage of oil and gas sales increased from 22% during the first nine months of 2006 to 28% during the first nine months of 2007. Our lease operating expenses per BOE increased from $11.91 during the first nine months of 2006 to $14.05 during the first nine months of 2007. The increase of 18% on a BOE basis was primarily caused by a high level of workover activity, inflation in the cost of oil field goods and services, and a change in labor billing practices. Workovers amounted to $11.3 million in the first nine months of 2007, as compared to $5.9 million of workover activity in the first nine months of 2006. The cost of oil field goods and services increased due to a higher demand in the industry. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to Council of Petroleum Accountants Societies ("COPAS") guidelines. This change in labor billing practices resulted in lower net general and administrative expense and higher amounts of lease operating expense being charged to us and our joint interest owners on properties we operate.

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 2007 and 2006 were 6.3% and 6.1%, respectively, of oil and gas sales.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased $26.3 million to $143.2 million during the first nine months of 2007, as compared to the first nine months of 2006. On a BOE basis, our DD&A rate increased from $10.30 during the first nine months of 2006 to $13.02 in the first nine months of 2007. The primary factors causing this rate increase were (1) additional drilling expenditures incurred during the past 12 months in relation to net oil and gas reserve additions over the same time period, and (2) the amount of expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, where the development of undeveloped reserves does not increase existing proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. The components of our DD&A expense were as follows (in thousands):

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	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Depletion	$ 138,826	$ 113,389
Depreciation	2,293	1,865
Accretion of asset retirement obligations	2,095	1,693
Total	$ 143,214	$ 116,947

Exploration and Impairment Costs. Our exploration and impairment costs increased $3.3 million to $26.2 million in the first nine months of 2007 compared to the first nine months of 2006. The components of exploration and impairment costs were as follows (in thousands):

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Exploration	$ 19,081	$ 21,161
Impairment	7,158	1,742
Total	$ 26,239	$ 22,903

During the first nine months of 2007, we participated in a non-operated exploratory well drilled in the Gulf Coast region that resulted in an insignificant amount of dry hole expense, as compared to the first nine months of 2006, during which we drilled two exploratory dry holes in the Rocky Mountains region and one exploratory dry hole in the Gulf Coast region, totaling $5.3 million. This reduction in exploratory dry hole expense was partially offset by an increase in geological and geophysical ("G&G") activity during the first nine months of 2007. G&G costs amounted to $10.5 million during the first nine months of 2007, as compared to $7.9 million in the first nine months of 2006. The impairment charges in 2007 and 2006 were related to the amortization of leasehold costs associated with individually insignificant unproved properties. The increase in impairment is due to an additional $51.8 million of unproved property being amortized during the nine months ended September 30, 2007, as compared to the same period in 2006.

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

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
General and administrative expenses	$ 52,338	$ 44,749
Reimbursements and allocations	(24,397)	(15,464)
General and administrative expense, net	$ 27,941	$ 29,285

General and administrative expense before reimbursements and allocations increased $7.6 million to $52.3 million during the first nine months of 2007. The largest components of the increase related to $5.2 million of additional salaries and wages for personnel hired during the past twelve months and $1.1 million in additional Production Participation Plan expense, attributable primarily to the Company's 2007 oil and gas property divestitures. The increase in reimbursements and allocations in the first nine months of 2007 was caused by increased salary expenses and a higher number of field workers on operated properties. In addition during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. These changes in labor billing practices resulted in higher reimbursements and allocations and higher amounts of lease operating expense being allocated to us and charged to our joint interest owners on properties we operate. Our net general and administrative expenses as a percentage of oil and gas sales remained consistent at 5% during the first nine months of 2007 compared to the first nine months of 2006.

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Change in Production Participation Plan Liability. For the nine months ended September 30, 2007, this non-cash expense increased to $6.4 million. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2008 under our Production Participation Plan ("Plan"). Although payments take place over the life of oil and gas properties contributed to the Plan, which for some properties is over 20 years, we must expense the present value of estimated future payments over the Plan's five year vesting period. This expense in 2007 and in 2006 primarily reflects changes to future cash flow estimates and related Plan liability due to the effect of a sustained higher price environment, recent drilling activity, and employees' continued vesting in the Plan. During the nine months ended September 30, 2007, the five-year average historical NYMEX prices used to estimate this liability increased $6.09 for crude oil and $0.53 for natural gas from December 31, 2006, as compared to increases of $5.05 for crude oil and $0.15 for natural gas for the nine months ended September 30, 2006. 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.

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

	Nine Months Ended September 30,	
	2007	**2006**
Credit Agreement	$ 20,035	$ 15,219
Senior Subordinated Notes	33,571	33,350
Amortization of debt issue costs and debt discount	3,793	3,922
Accretion of tax sharing liability	1,142	1,549
Other	445	742
Capitalized interest	(2,472)	(303)
Total interest expense	$ 56,514	$ 54,479

The increase in interest expense was mainly due to additional borrowings outstanding in 2007 under our credit agreement, which were partially offset by increased capitalized interest related to construction and expansion of processing facilities.

Our weighted average debt outstanding during the first nine months of 2007 was $996.1 million versus $934.2 million in the first nine months of 2006. Our weighted average effective cash interest rate was 7.2% during the first nine months of 2007 versus 7.0% during the first nine months of 2006. 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 7.7% during the first nine months of 2007 versus 7.5% during the first nine months of 2006.

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Unrealized Derivative Loss. During the first quarter of 2007, we determined that the forecasted transactions, to which certain crude oil collars had been designated, were no longer probable of occurring prior to the contracts expiring from April through December of 2007. We therefore reclassified the net losses attributable to these hedges out of accumulated other comprehensive loss and recognized $1.1 million in unrealized derivative losses in the condensed consolidated statements of income in the first quarter of 2007. Subsequent to the first quarter of 2007, Whiting recognized an additional $0.1 million in unrealized mark-to-market losses on non-qualifying derivatives. We discontinued hedge accounting prospectively for these collars. During the first nine months of 2006, we did not recognize any unrealized derivative losses.

Income Tax Expense. Income tax expense totaled $50.6 million for the first nine months of 2007 and $62.2 million for the first nine months of 2006. Our effective income tax rate increased from 32.6% for the first nine months of 2006 to 37.4% for the first nine months of 2007. Our effective income tax rate was higher for the nine months ended September 30, 2007 primarily due to several non-recurring benefits recognized in 2006 consisting of: a $4.3 million deferred tax benefit for 2005 enhanced oil recovery (“EOR”) tax credits; a $2.3 million benefit relating to a true-up of our effective tax rate to our 2005 state returns as filed; and deferred tax benefits of $1.2 million as a result of state tax legislation enacted in 2006. In addition, during the third quarter of 2007, we incurred incremental current tax expense of $1.5 million as a result of filing our 2006 returns and increasing our foreign tax credit valuation allowance. This expense was partially offset by a $0.6 million deferred tax benefit recognized in 2007 for EOR credits relating to 2003 and 2004.

Net Income. Net income decreased from $128.4 million during the first nine months of 2006 to $84.9 million during the first nine months of 2007. The primary reasons for this decrease included a 3% decrease in equivalent volumes sold, a 10% decrease in gas prices (net of hedging) between periods, higher lease operating expense, DD&A, exploration and impairment, change in Production Participation Plan liability, interest expense and unrealized derivative loss. The decreased production and pricing and increased expenses were partially offset by the gain on sale of properties and lower production taxes, general and administrative expenses and income taxes in the first nine months of 2007.

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Three Months Ended September 30, 2007 Compared to Three Months Ended September 30, 2006

Selected Operating Data:	Three Months Ended September 30, 2007	2006
Net production:		
Oil (MMbls)	2.5	2.5
Natural gas (Bcf)	7.6	8.2
Total production (MMBOE)	3.7	3.9
Net sales (in millions):		
Oil(1)	$ 167.4	$ 156.7
Natural gas(1)	38.2	51.1
Total oil and natural gas sales	$ 205.6	$ 207.8
Average sales prices:		
Oil (per Bbl)	$ 67.51	$ 62.11
Effect of oil hedges on average price (per Bbl)	(0.85)	(0.15)
Oil net of hedging (per Bbl)	$ 66.66	$ 61.96
Average NYMEX price	$ 75.03	$ 70.55
Natural gas (per Mcf)	$ 5.06	$ 6.23
Effect of natural gas hedges on average price (per Mcf)	-	-
Natural gas net of hedging (per Mcf)	$ 5.06	$ 6.23
Average NYMEX price	$ 6.16	$ 6.58
Cost and expense (per BOE):		
Lease operating expenses	$ 14.30	$ 11.88
Production taxes	$ 3.53	$ 3.21
Depreciation, depletion and amortization expense	$ 13.19	$ 10.99
General and administrative expenses	$ 2.88	$ 2.58

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $2.2 million to $205.6 million in the third quarter of 2007 compared to the third quarter of 2006. Sales are a function of volumes sold and average sales prices. Our oil sales volumes remained consistent between quarters, and our gas sales volumes decreased 8% between periods. The volume decline resulted primarily from property sales and normal field production decline, which factors were largely offset by production increases from development activities. The property sales account for a decline of approximately 65 MBOE, 72% of which related to natural gas. During the third quarter of 2007, we converted several of our production wells to injectors at our North Ward Estes field, as the reservoir was pressured up in the Phase 1 area in preparation for CO_2 injection. Our average price for oil before effects of hedging increased 9% and our average price for natural gas before effects of hedging decreased 19% between periods.

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Loss on Oil and Natural Gas Hedging Activities. We hedged 50% of our oil volumes during the third quarter of 2007, incurring derivative settlement losses of $2.1 million, and 54% of our oil volumes during the third quarter of 2006, incurring derivative settlement losses of $0.4 million. We did not hedge any gas volumes during the third quarter of 2007. We hedged 59% of our gas volumes during the third quarter of 2006, incurring no realized hedging gains or losses. See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil hedges as of October 1, 2007.

Gain on sale of properties. During the third quarter of 2007, 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. There was no gain on sale of properties during the third quarter of 2006.

Lease Operating Expenses. Our lease operating expenses increased $7.3 million to $53.5 million in the third quarter of 2007 compared to the third quarter of 2006. Our lease operating expense as a percentage of oil and gas sales increased from 22% during the third quarter of 2006 to 26% during the third quarter of 2007. Our lease operating expenses per BOE increased from $11.88 during the third quarter of 2006 to $14.30 during the third quarter of 2007. The increase of 20% on a BOE basis was primarily caused by a high level of workover activity, inflation in the cost of oil field goods and services, and a change in labor billing practices. Workovers amounted to $4.7 million in the third quarter of 2007, as compared to $1.8 million of workover activity in the third quarter of 2006, and the cost of oil field goods and services increased due to a higher demand in the industry. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. This change in labor billing practices resulted in lower net general and administrative expense and higher amounts of lease operating expense being charged to us and our joint interest owners on properties we operate.

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 2007 and 2006 were 6.4% and 6.0%, respectively, of oil and gas sales. The 2007 rate was greater than the 2006 rate due to the change in the property mix associated with recent divestitures and drilling successes.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased $6.6 million to $49.3 million during the third quarter of 2007, as compared to the third quarter of 2006. On a BOE basis, our DD&A rate increased from $10.99 during the third quarter of 2006 to $13.19 in the third quarter of 2007. The primary factors causing this rate increase were (1) additional drilling expenditures incurred during the past 12 months in relation to net oil and gas reserve additions over the same time period, and (2) the amount of expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, where the development of undeveloped reserves does not increase existing proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. The components of our DD&A expense were as follows (in thousands):

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	Three Months Ended September 30,	
	2007	2006
Depletion	$ 47,777	$ 41,430
Depreciation	790	735
Accretion of asset retirement obligations	741	572
Total	$ 49,308	$ 42,737

Exploration and Impairment Costs. Our exploration and impairment costs increased $3.8 million to $10.4 million in the third quarter of 2007 compared to the third quarter of 2006. The components of exploration and impairment costs were as follows (in thousands):

	Three Months Ended September 30,	
	2007	2006
Exploration	$ 7,904	$ 5,618
Impairment	2,516	1,029
Total	$ 10,420	$ 6,647

During the third quarter of 2007, exploration costs increased due to a higher level of geological and geophysical ("G&G") activity. G&G costs amounted to $5.0 million in the third quarter of 2007, as compared to $3.1 million in the third quarter of 2006. The impairment charges in 2007 and 2006 were related to the amortization of leasehold costs associated with individually insignificant unproved properties. The increase in impairment is due to an additional $28.1 million of unproved property being amortized during the three months ended September 30, 2007, as compared to the same period in 2006.

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

	Three Months Ended September 30,	
	2007	2006
General and administrative expenses	$ 19,341	$ 15,680
Reimbursements and allocations	(8,561)	(5,645)
General and administrative expense, net	$ 10,780	$ 10,035

General and administrative expense before reimbursements and allocations increased $3.7 million to $19.3 million during the third quarter of 2007. The largest components of the increase related to $1.8 million of additional salaries and wages for personnel hired during the past twelve months and $2.1 million in additional Production Participation Plan expense, attributable primarily to the Company's 2007 oil and gas property divestitures. The increase in reimbursements and allocations in the third quarter of 2007 was caused by increased salary expenses and a higher number of field workers on operated properties. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. These changes in labor billing practices resulted in higher reimbursements and allocations to us and higher amounts of lease operating expense being allocated to us and charged to our joint interest owners on properties we operate. Our general and administrative expenses as a percentage of oil and gas sales remained constant at 5% during the three months ended September 30, 2007 compared to the same period in 2006.

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Change in Production Participation Plan Liability. For the three months ended September 30, 2007, this non-cash expense increased to $2.3 million. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2008 under our Production Participation Plan ("Plan"). Although payments take place over the life of oil and gas properties contributed to the Plan, which for some properties is over 20 years, we must expense the present value of estimated future payments over the Plan's five year vesting period. This expense in 2007 and in 2006 primarily reflects changes to future cash flow estimates and related Plan liability due to the effect of a sustained higher price environment, recent drilling activity, and employees' continued vesting in the Plan. During the three months ended September 30, 2007, the five-year average historical NYMEX prices used to estimate this liability increased $2.32 for crude oil and $0.15 for natural gas from June 30, 2007, as compared to an increase of $1.60 for crude oil and a decrease of $0.29 for natural gas for the three months ended September 30, 2006. 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.

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

	Three Months Ended September 30, 2007	**2006**
Credit Agreement	$ 4,595	$ 5,710
Senior Subordinated Notes	11,199	11,177
Amortization of debt issue costs and debt discount	1,251	1,291
Accretion of tax sharing liability	381	498
Other	245	300
Capitalized interest	(1,408)	(97)
Total interest expense	$ 16,263	$ 18,879

The decrease in interest expense was mainly due to repayments under our credit agreement in the third quarter of 2007 and increased capitalized interest related to construction and expansion of processing facilities.

Our weighted average debt outstanding during the third quarter of 2007 was $868.8 million versus $952.8 million in the third quarter of 2006. Our weighted average effective cash interest rate was 7.4% during the third quarter of 2007 versus 7.2% during the third quarter of 2006. 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 7.9% during the third quarter of 2007 versus 7.7% during the third quarter of 2006.

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Unrealized Derivative Loss. During the first quarter of 2007, we determined that the forecasted transactions, to which certain crude oil collars had been designated, were no longer probable of occurring prior to the contracts expiring from April through December of 2007. We therefore reclassified the net losses attributable to these hedges out of accumulated other comprehensive loss and recognized $1.1 million in unrealized derivative losses in the condensed consolidated statements of income in the first quarter of 2007. Subsequent to the first quarter of 2007, Whiting recognized an additional $0.1 million in unrealized mark-to-market losses on non-qualifying derivatives. We discontinued hedge accounting prospectively for these collars. During the third quarter of 2006, we did not recognize any unrealized derivative losses.

Income Tax Expense. Income tax expense totaled $29.6 million for the third quarter of 2007 and $19.3 million for the third quarter of 2006. Our effective income tax rate increased from 28.0% for the third quarter of 2006 to 38.3% for the same period in 2007. Our effective income tax rate was higher in the third quarter of 2007 primarily due to the recognition in 2006 of a $1.8 million deferred tax benefit for 2005 EOR tax credits and a $2.3 million benefit relating to a true-up of our effective tax rate to our 2005 state returns as filed. In addition, during the third quarter of 2007, we incurred incremental current tax expense of $1.5 million as a result of filing our 2006 returns and increasing our foreign tax credit valuation allowance. This expense was partially offset by a $0.6 million deferred tax benefit recognized in 2007 for EOR credits relating to 2003 and 2004.

Net Income. Net income decreased from $49.5 million during the third quarter of 2006 to $47.7 million during the third quarter of 2007. This decrease resulted from a 4% decrease in equivalent volumes sold and a 19% decrease in gas prices (net of hedging) between periods, which factors were partially offset by an 8% increase in oil prices (net of hedging) between periods. In addition, there were higher lease operating expense, production taxes, DD&A, exploration and impairment, general and administrative expenses, change in Production Participation Plan expenses, unrealized derivative losses and income taxes. The decreased production and pricing and increased expenses were partially offset by the gain on sale of properties and lower interest expense in the third quarter of 2007.

Liquidity and Capital Resources

Overview. At December 31, 2006, our debt to total capitalization ratio was 45.6%, we had $10.4 million of cash on hand and $1,186.7 million of stockholders' equity. At September 30, 2007, our debt to total capitalization ratio was 36.2%, we had $8.7 million of cash on hand and $1,472.9 million of stockholders' equity. In the first nine months of 2007, we generated $272.6 million of cash provided by operating activities, a decrease of $79.3 million over the same period in 2006. Cash provided by operating activities decreased primarily because of lower average sales prices for crude oil and natural gas, slightly lower production volumes and higher cash lease operating expenses. We also generated $50.8 million from financing activities primarily consisting of $210.4 million in net proceeds received from the issuance of our common stock, offset by net repayments under our credit agreement totaling $160.0 million. Cash on hand and cash flows from operating and financing activities, as well as proceeds from property divestitures, were primarily used to finance $372.8 million of exploration and development expenditures paid in the first nine months of 2007 and $16.7 million of cash acquisition capital expenditures to acquire the Parshall Prospect in North Dakota. The following chart details our exploration and development expenditures incurred by region during the first nine months of 2007 (in thousands).

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	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Permian Basin	$ 125,899	$ 2,981	$ 128,880	33%
Rocky Mountains	116,300	10,585	126,885	32%
Mid-Continent	99,296	1,521	100,817	26%
Gulf Coast	15,646	3,202	18,848	5%
Michigan	14,518	792	15,310	4%
Total incurred	371,659	19,081	390,740	100%
Increase in accrued capital expenditures	(17,973)	-	(17,973)	
Total paid	$ 353,686	$ 19,081	$ 372,767	

We continually evaluate our capital needs and compare them to our capital resources. Our 2007 budgeted exploration and development expenditures for the further development of our property base are $525.0 million, an increase from the $485.1 million incurred on exploration and development expenditures during 2006, primarily due to additional drilling opportunities that have been identified in our Boies Ranch and Jimmy Gulch prospect areas in the Piceance Basin, our Robinson Lake area in the Williston Basin, and other core areas. Although we have no specific budget for property acquisitions in 2007, we will continue to selectively pursue property acquisitions that complement our existing core property base. We expect to fund our 2007 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 $525.0 million, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, or agreements with industry partners. Our level of exploration and development expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future.

Credit Agreement. Our 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, 2007, had a borrowing base of $875.0 million with $220.0 million outstanding, leaving $655.0 million of available borrowing capacity. The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to 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. In October 2007, the syndicate of banks approved an increase in the borrowing base under the credit agreement to $900.0 million, effective November 1, 2007.

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 re-borrow up to the borrowing base in effect from 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, 2007, letters of credit totaling $0.2 million were outstanding under the credit 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. We have consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. 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. As of September 30, 2007, the effective weighted average interest rate on the outstanding principal balance under the credit agreement was 6.4%.

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) 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, 2007. 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 our 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 $250.0 million of 7% Senior Subordinated Notes due 2014 at par.

In April 2005, we issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. The notes were issued at 98.507% of par, and the associated discount is being amortized to interest expense over the term of the notes.

In May 2004, we issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. The notes were issued at 99.26% of par, and the associated discount is being amortized to interest expense over the term of the 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, 2007. Three of 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.

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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. 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 following table summarizes our obligations and commitments as of September 30, 2007 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include Production Participation Plan liabilities since we cannot determine with accuracy the timing of future payment amounts (in thousands):

	Payments due by period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-term debt (a)	$ 840,000	$ -	$ 220,000	$ 150,000	$ 470,000
Cash interest expense on debt (b)	309,663	58,658	117,317	87,926	45,762
Asset retirement obligation (c)	40,942	624	1,009	3,008	36,301
Tax sharing liability (d)	27,052	3,565	5,988	5,044	12,455
Derivative contract liability fair value (e)	28,507	23,959	4,548	-	-
Purchasing obligations (f)	295,318	41,211	102,476	97,090	54,541
Drilling rig contracts (g)	56,106	29,340	26,766	-	-
Operating leases (h)	6,700	2,000	4,040	660	-
Total	$ 1,604,288	$ 159,357	$ 482,144	$ 343,728	$ 619,059

(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 debt 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 7.7% 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 a fixed interest rate of 6.4%.

(c) Asset retirement obligations represent the present value of estimated amounts expected to be incurred to plug, abandon and remediate oil and gas properties.

(d) Amounts shown represent the estimated present value of 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, the increased tax bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax basis for the years ending on or prior to December 31, 2013. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years.

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(e) We have entered into derivative contracts, primarily costless collars, to hedge our exposure to crude oil price fluctuations. As of September 30, 2007, 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 Texas County, Oklahoma and our North Ward Estes field in Ward County, 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 two drilling rigs under contract through 2008, one drilling rig through 2009 and one drilling rig through 2010, in addition to a workover rig under contract through 2009, all of which are operating in the Rocky Mountains region. As of September 30, 2007, early termination of these contracts would have required maximum penalties of $41.2 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 87,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2010, and an additional 30,100 square feet of office space in Midland, Texas through February 15, 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.

New Accounting Policies

In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, an interpretation of Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* ("FIN 48"). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we recognized a $0.3 million increase in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007, balance of retained earnings. The total amount of unrecognized tax benefits as of the adoption date was $0.4 million, with an additional $0.1 million in unrecognized tax benefits during the third quarter of 2007. Our policy is to recognize interest and penalties accrued related to unrecognized tax benefits within income tax expense.

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New Accounting Pronouncements

In September 2006, the FASB issued Statement No. 157, *Fair Value Measurements* ("SFAS 157"). The adoption of SFAS 157 is not expected to have a material impact on our consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop the measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years.

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. Under SFAS 159, a company may elect to use fair value to measure many financial instruments and certain other assets and liabilities at fair value. We decided not to elect fair value accounting for any of our eligible items. The adoption of SFAS 159 therefore will have no impact on our financial position, cash flows or results of operations. If the use of fair value is elected (the fair value option), 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. At the adoption date, unrealized gains and losses on existing items for which fair value has been elected are reported as a cumulative adjustment to beginning retained earnings. Subsequent to the adoption of SFAS 159, changes in fair value are recognized in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007.

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, 2006.

Effects of Inflation and Pricing

We experienced increased costs during 2006 and the first nine months of 2007 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, continued high 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, including our ability to realize cost savings from completed acquisitions; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete our planned and 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 Part II, Item 1A of our Quarterly Report on Form 10-Q for the period ending June 30, 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, 2006 and have not materially changed since that report was filed.

Our outstanding hedges as of October 1, 2007 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)	NYMEX Floor/Ceiling
Crude Oil	10/2007 to 12/2007	110,000	$49.00/$71.50
Crude Oil	10/2007 to 12/2007	300,000	$50.00/$76.50
Crude Oil	01/2008 to 03/2008	110,000	$49.00/$70.65
Crude Oil	01/2008 to 03/2008	120,000	$60.00/$73.90
Crude Oil	01/2008 to 03/2008	100,000	$65.00/$80.30
Crude Oil	04/2008 to 06/2008	110,000	$48.00/$71.60
Crude Oil	04/2008 to 06/2008	120,000	$60.00/$74.65
Crude Oil	04/2008 to 06/2008	100,000	$65.00/$80.50
Crude Oil	07/2008 to 09/2008	110,000	$48.00/$70.85
Crude Oil	07/2008 to 09/2008	120,000	$60.00/$75.60
Crude Oil	07/2008 to 09/2008	100,000	$65.00/$81.00
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

The crude oil collars 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 beyond the ceiling. For the 2007 crude oil contracts listed above, a hypothetical $1.00 change in the NYMEX price would cause a change in the gain (loss) on hedging activities in 2007 of $1.2 million.

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, 2007 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	2007 Price Per MMBtu
Natural Gas	10/2007 to 05/2011	29,000	$4.75
Natural Gas	10/2007 to 09/2012	66,000	$4.21

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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, 2007. Based upon their evaluation of these disclosure 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, 2007 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, 2007 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

You should carefully consider each of the risks in Part II, Item 1A of our Quarterly Report on Form 10-Q for the period ended June 30, 2007, together with all of the other information contained in this report, before making an investment decision with respect to our securities. If any of the risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected and you may lose all or part of your investment.

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 31st day of October, 2007.

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
(10.1)	Summary of Non-Employee Director Compensation for Whiting Petroleum Corporation.
(31.1)	Certification by 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.