WHITING PETROLEUM CORP
Form 10-Q
April 27, 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 **March 31, 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 April 16, 2007: 37,053,071 shares.

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PART I – FINANCIAL INFORMATION

Item 1. **Consolidated Financial Statements (Unaudited)**

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

	March 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 8,188	$ 10,372
Accounts receivable trade, net	90,194	97,831
Deferred income taxes	5,208	3,025
Prepaid expenses and other	13,544	10,484
Total current assets	117,134	121,712
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	2,952,031	2,828,282
Unproved properties	60,696	55,297
Other property and equipment	43,647	44,902
Total property and equipment	3,056,374	2,928,481
Less accumulated depreciation, depletion and amortization	(535,682)	(495,820)
Total property and equipment, net	2,520,692	2,432,661
DEBT ISSUANCE COSTS	18,233	19,352
OTHER LONG-TERM ASSETS	12,726	11,678
TOTAL	$ 2,668,785	$ 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)

	March 31, 2007	December 31, 2006
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 31,797	$ 21,077
Accrued liabilities	53,319	58,504
Accrued interest	20,687	9,124
Oil and gas sales payable	17,634	19,064
Accrued employee compensation and benefits	4,159	17,800
Production taxes payable	6,088	9,820
Current portion of tax sharing liability	3,565	3,565
Current portion of derivative liability	10,071	4,088
Total current liabilities	147,320	143,042
NON-CURRENT LIABILITIES:		
Long-term debt	1,055,975	995,396
Asset retirement obligations	39,735	36,982
Production Participation Plan liability	27,535	25,443
Tax sharing liability	23,987	23,607
Deferred income taxes	169,942	165,031
Long-term derivative liability	7,175	5,248
Other long-term liabilities	4,211	3,984
Total non-current liabilities	1,328,560	1,255,691
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $0.001 par value; 75,000,000 shares authorized, 37,053,071 and 36,947,681 shares issued and outstanding as of March 31, 2007 and December 31, 2006, respectively	37	37
Additional paid-in capital	754,977	754,788
Accumulated other comprehensive loss	(10,199)	(5,902)
Retained earnings	448,090	437,747
Total stockholders' equity	1,192,905	1,186,670
TOTAL	$ 2,668,785	$ 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 March 31, 2007	Three Months Ended March 31, 2006
REVENUES AND OTHER INCOME:		
Oil and natural gas sales	$ 159,714	$ 189,865
Loss on oil and natural gas hedging activities	-	(9,524)
Interest income and other	209	289
Total revenues and other income	159,923	180,630
COSTS AND EXPENSES:		
Lease operating	49,057	44,398
Production taxes	9,612	11,935
Depreciation, depletion and amortization	44,571	35,300
Exploration and impairment	9,176	7,042
General and administrative	8,285	9,611
Change in Production Participation Plan liability	2,092	2,074
Interest expense	19,497	16,973
Unrealized derivative loss	1,114	-
Total costs and expenses	143,404	127,333
INCOME BEFORE INCOME TAXES	16,519	53,297
INCOME TAX EXPENSE:		
Current	626	2,031
Deferred	5,227	18,276
Total income tax expense	5,853	20,307
NET INCOME	$ 10,666	$ 32,990
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 0.29	$ 0.90
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	36,771	36,726
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	36,861	36,743

See notes to condensed consolidated financial statements.

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

	Three Months Ended March 31, 2007	Three Months Ended March 31, 2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 10,666	$ 32,990
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	44,571	35,300
Deferred income taxes	5,227	18,276
Amortization of debt issuance costs and debt discount	1,276	1,323
Accretion of tax sharing liability	380	525
Stock-based compensation	1,119	779
Unproved leasehold impairments	2,316	140
Change in Production Participation Plan liability	2,092	2,074
Unrealized derivative loss	1,114	-
Other non-current	(1,558)	(2,053)
Changes in current assets and liabilities:		
Accounts receivable trade	7,637	8,866
Prepaid expenses and other	(3,060)	(4,655)
Accounts payable and accrued liabilities	(953)	20,872
Accrued interest	11,563	7,772
Other current liabilities	(20,029)	(10,921)
Net cash provided by operating activities	62,361	111,288
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(16,718)	(15,773)
Drilling and development capital expenditures	(109,402)	(118,788)
Proceeds from sale of oil and gas properties	1,281	-
Net cash used in investing activities	(124,839)	(134,561)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings under credit agreement	100,000	30,000
Repayments of long-term borrowings under credit agreement	(40,000)	(10,000)
Tax effect from restricted stock vesting	294	260
Net cash provided by financing activities	60,294	20,260
NET CHANGE IN CASH AND CASH EQUIVALENTS	(2,184)	(3,013)
CASH AND CASH EQUIVALENTS:		
Beginning of period	10,372	10,382
End of period	$ 8,188	$ 7,369
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash (refunded) paid for income taxes	$ (73)	$ 185
Cash paid for interest	$ 6,741	$ 7,353
NONCASH INVESTING ACTIVITIES:		
(Increase) decrease in accrued capital expenditures	$ (6,427)	$ 405

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	-	-	-	24,140	-	-	24,140	24,140
Realized loss on settled derivative contracts, net of related taxes	-	-	-	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	-	-	-	-	-	10,666	10,666	10,666
Change in derivative fair values, net of taxes	-	-	-	(5,001)	-	-	(5,001)	(5,001)
Unrealized derivative loss, net of related taxes	-	-	-	704	-	-	704	704
Restricted stock issued	142	-	-	-	-	-	-	-
Restricted stock forfeited	(10)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(27)	-	(1,224)	-	-	-	(1,224)	-
Tax effect from restricted stock vesting	-	-	294	-	-	-	294	-
Stock-based compensation	-	-	1,119	-	-	-	1,119	-
Adoption of FIN 48	-	-	-	-	-	(323)	(323)	-
BALANCES—March 31, 2007	37,053	$ 37	$ 754,977	$ (10,199)	$ -	$ 448,090	$ 1,192,905	$ 6,369

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 subsidiaries.

Consolidated Financial Statements—The unaudited condensed consolidated financial statements include the accounts of Whiting Petroleum Corporation and its 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 significant intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, all material adjustments considered necessary for a fair presentation of the Company’s interim results have been reflected. 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.

Earnings Per Share—Basic net income per common share of stock is calculated by dividing net income by the weighted average number of common shares outstanding during each period. Diluted net income per common share of stock 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. The dilutive effect of these securities was immaterial to the calculation.

Reclassifications— Certain prior period balances were reclassified to conform to the current year presentation, and such reclassifications had no impact on net income or stockholders’ equity previously reported.

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, and there were no additions or reductions to the Company’s unrecognized tax benefits during the three months ended March 31, 2007. Included in the balance at January 1, 2007, are $0.1 million of tax positions, the allowance of which would positively affect the annual effective income tax rate. It is reasonably possible that unrecognized tax benefits in the amount of $0.3 million relating to gas imbalances will decrease within the next 12 months, as Whiting is in the process of applying for a change in the method of accounting to a method prescribed by the Internal Revenue Service (“IRS”).

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

U.S. Federal	11/23/2003 – 12/31/2006
U.S. states	11/23/2003 – 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 quarter ended March 31, 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 March 31, 2007 relating to unrecognized tax benefits.

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2. ACQUISITIONS AND DIVESTITURES

2007 Acquisitions

There were no significant acquisitions during the first quarter of 2007.

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. The remaining two wells are planned to be drilled during the remainder of 2007.

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 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 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 March 31, 2007 and December 31, 2006 (in thousands):

	March 31, 2007	December 31, 2006
Credit Agreement	$ 440,000	$ 380,000
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $648 and $687, respectively	148,281	147,820
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $2,306 and $2,424, respectively	217,694	217,576
7% Senior Subordinated Notes due 2014	250,000	250,000
Total debt	$ 1,055,975	$ 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 March 31, 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 March 31, 2007, the outstanding principal balance under the credit agreement was $440.0 million.

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 March 31, 2007, letters of credit totaling $0.3 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 March 31, 2007, weighted average interest rate on the outstanding principal balance under the credit agreement was 6.7%.

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 (as defined in the credit agreement) ratio 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 March 31, 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 $242.8 million as of March 31, 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 $215.3 million as of March 31, 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 March 31, 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. In addition, Whiting Oil and Gas’ credit agreement restricts the ability of the Company’s subsidiaries to make certain payments, including principal on the notes, to Whiting Petroleum Corporation. The Company was in compliance with these covenants as of March 31, 2007. Three of the Company’s wholly-owned operating subsidiaries, Whiting Oil and Gas, Whiting Programs, Inc. and Equity Oil Company (the “Guarantors”), have

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fully, unconditionally, jointly and severally guaranteed the Company's obligations under the notes. The Company does not have any subsidiaries other than the Guarantors, minor or otherwise, within the meaning of Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission, and Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in guarantor subsidiaries.

Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of $75.0 million of its 7.25% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that the Company receives the fixed rate of 7.25% and pays the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus the Company's margin of 2.345% is less than 7.25%, the Company receives a payment from the counterparty equal to the difference in rate times $75.0 million for the six month period. When LIBOR plus the Company's margin of 2.345% is greater than 7.25%, the Company pays the counterparty an amount equal to the difference in rate times $75.0 million for the six month period. As of March 31, 2007, the Company has recorded a long-term liability of $1.1 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 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 three months ended March 31, 2007 (in thousands):

Asset retirement obligation, January 1, 2007	$ 37,534
Additional liability incurred	407
Revisions in estimated cash flows	2,821
Accretion expense	607
Obligations on sold properties	(185)
Liabilities settled	(837)
Asset retirement obligation, March 31, 2007	$ 40,347

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.

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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.

All derivative instruments, other than those that meet the normal purchase and sales exceptions, are recorded on the balance sheet as either an asset or liability measured at fair value. Changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Hedge accounting treatment allows unrealized gains and losses on effective cash flow hedges to be deferred in accumulated other comprehensive income (loss) until the hedged transactions occur. Realized gains and losses on cash flow hedges are transferred from accumulated other comprehensive income (loss) and recognized in earnings as gain (loss) on oil and natural gas hedging activities. Realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Gains and losses from the change in the fair value of derivative instruments that do not qualify as a hedge or that are not designated as a hedge, as well as the ineffective portion of hedge derivatives, if any, are reported in the condensed consolidated statements of income as unrealized derivative (gain) loss. Derivative settlements are included in cash flows from operating activities.

At March 31, 2007, accumulated other comprehensive loss consisted of $17.2 million ($10.2 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 quarter ended March 31, 2007, Whiting recognized no realized gains or losses on commodity derivative settlements. For the quarter ended March 31, 2006, Whiting recognized realized losses of $9.5 million on commodity derivative settlements. Based on the estimated fair value of the derivative contracts at March 31, 2007, the Company expects to reclassify net losses of $9.0 million into earnings related to derivative contracts during the next twelve months; however, actual gains and losses recognized may differ materially. The Company has hedged 3.7 MMBbl of crude oil volumes through 2007 and 2.8 MMBbl of crude oil volumes through 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 the specified time periods. The Company therefore reclassified the net loss 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 as of March 31, 2007. The Company also 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.

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6. STOCKHOLDERS' EQUITY

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 participating employee 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 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 March 31, 2007 as well as activity during the three 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, 2006	203,264	$ 39.33
Granted	142,066	$ 45.42
Vested	(90,711)	$ 36.50
Forfeited	(9,719)	$ 44.23
Restricted stock awards nonvested, March 31, 2007	244,900	$ 43.72

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 March 31, 2007, there was $7.0 million of total unrecognized compensation cost related to unvested restricted stock granted under the stock incentive plans. That cost is expected to be recognized over a weighted average period of 2.3 years.

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

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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.

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 three months ended March 31, 2007 and 2006 amounted to $2.5 million and $3.0 million, respectively, charged to general and administrative expense and $0.5 million and $0.6 million, respectively, charged to exploration expense.

Pursuant to the terms of the Plan, (1) employees who terminate their employment with the Company vest at a rate of 20% per year in future Plan year payments, which are attributable to their interests in the income allocated to the Plan for such year; (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 March 31, 2007, the Company used five-year average historical NYMEX prices of $48.25 for crude oil and $6.28 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 March 31, 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 $73.5 million. This amount includes $11.4 million attributable to proved undeveloped oil and gas properties and $3.0 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. The following table presents changes in the estimated long-term liability related to the Plan for the three months ended March 31, 2007 (in thousands):

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Production Participation Plan liability, January 1, 2007	$ 25,443
Change in liability for accretion, vesting and change in estimate	5,128
Reduction in liability for cash payments accrued and recognized as compensation expense	(3,036)
Production Participation Plan liability, March 31, 2007	$ 27,535

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

	Three Months Ended March 31,	
	2007	**2006**
General and administrative expense	$ 1,755	$ 1,742
Exploration expense	337	332
Total	$ 2,092	$ 2,074

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 $26.2 million.

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During the first three months of 2007, the Company did not make any payments under this agreement but did recognize $0.4 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 March 31, 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 are expected to be utilized by Alliant Energy in 2007. However, on a stand-alone basis Whiting would have been unable to use the credits in its 2002 tax return. The Company expects to be paid during 2007 for the Section 29 credits, which is when Alliant Energy expects to receive the benefit for them. The Company has a current receivable in the amount of $4.1 million as of March 31, 2007 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 26,500 square feet of office space in Midland, Texas through February 15, 2012. Rental expense for the first three months of 2007 and 2006 was $0.6 million and $0.5 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of March 31, 2007 are as follows (in thousands):

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2007	$ 1,310
2008	1,759
2009	1,772
2010	1,540
2011	329
Thereafter	42
Total	$ 6,752

Purchase Contract— The Company has entered into two take-or-pay purchase agreements, one agreement in July 2005 for 9.5 years and one agreement in March 2006 for 8 years, 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 March 31, 2007, future commitments under the purchase agreements amounted to $303.9 million through 2014.

Drilling Contracts—The Company entered into three separate three-year agreements in 2005 for drilling rigs, a two-year agreement in February 2006 for a workover rig, and a three-year agreement in September 2006 for an additional drilling rig, all operating in the Rocky Mountains region. As of March 31, 2007, these agreements had total commitments of $43.3 million and early termination would require maximum penalties of $30.2 million. No other drilling rigs working for the Company are currently under long-term contracts or contracts which cannot be terminated at the end of the well that is currently being drilled.

Price-sharing Agreement—The Company, as part of a 2002 purchase transaction, agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2007 increased to 50% of the actual price received in excess of $20.98 per barrel. As of March 31, 2007, approximately 34,900 net barrels of crude oil per month (5% of March 2007 net crude oil production) are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. For the three month periods ended March 31, 2007 and 2006, the Company paid $1.8 million and $2.2 million, respectively, under this agreement. As of March 31, 2007 and 2006, the Company had accrued an additional $0.5 million and $0.7 million, respectively, as a current payable.

Litigation—The Company is subject to litigation claims and governmental and regulatory controls 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.

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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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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 and Equity Oil Company. When the context requires, we refer to these entities separately.

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. Some, but not all, of the risks and uncertainties include: 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; 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; 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; risks arising out of our hedging transactions and other risks described under the caption "Risk Factors" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

Overview

We are 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. Over the last six years, we have emphasized the acquisition of properties that provided current production and upside potential through further development. Our drilling activity is directed at this development, specifically on projects that we believe provide repeatable successes in particular fields. Our combination of acquisitions and development allows us to direct our capital resources to what we believe to be the most advantageous investments.

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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 provided a foothold 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.

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, our results of operations, the quantities of oil and gas reserves that we can economically produce and our access to capital.

Although independent engineers estimated probable and possible reserves relating to certain 2006 and prior year producing property acquisitions, we, consistent with our present acquisition practices, have associated substantially all acquisition costs with proved reserves. Because of our recent acquisition activity, our discussion and analysis of our historical financial condition and results of operations for the periods discussed below may not necessarily be comparable with or applicable to our future results of operations.

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Results of Operations

Three Months Ended March 31, 2007 Compared to Three Months Ended March 31, 2006

Selected Operating Data:	Three Months Ended March 31, 2007	2006
Net production:		
Oil (MMbls)	2.2	2.4
Natural gas (Bcf)	7.7	7.8
Total production (MMBOE)	3.5	3.7
Net sales (in millions):		
Oil(1)	$ 110.8	$ 130.5
Natural gas(1)	48.9	59.4
Total oil and natural gas sales	$ 159.7	$ 189.9
Average sales prices:		
Oil (per Bbl)	$ 49.33	$ 55.02
Effect of oil hedges on average price (per Bbl)	-	(3.79)
Oil net of hedging (per Bbl)	$ 49.33	$ 51.23
Average NYMEX price	$ 58.12	$ 63.53
Natural gas (per Mcf)	$ 6.33	$ 7.62
Effect of natural gas hedges on average price (per Mcf)	-	(0.07)
Natural gas net of hedging (per Mcf)	$ 6.33	$ 7.55
Average NYMEX price	$ 6.77	$ 9.01
Cost and expense (per BOE):		
Lease operating expenses	$ 13.88	$ 12.09
Production taxes	$ 2.72	$ 3.25
Depreciation, depletion and amortization expense	$ 12.62	$ 9.62
General and administrative expenses	$ 2.34	$ 2.62

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $30.2 million to $159.7 million in the first quarter of 2007 compared to the first quarter of 2006. Sales are a function of volumes sold and average sales prices. Our oil sales volumes decreased 5% and our gas sales volumes decreased 1% between periods. The volume declines resulted primarily from production shut-ins due to a fire at a third-party refinery and normal field production decline, which was partially offset by production increases from 12 months of drilling activity and recent acquisitions. As a result of the refinery fire, approximately 34,000 BOE of production from the Postle field was shut-in or restricted from February 19 through March 8, 2007. Our average price for oil before effects of hedging decreased 10% and our average price for natural gas before effects of hedging decreased 17% between periods.

Loss on Oil and Natural Gas Hedging Activities. We hedged 60% of our oil volumes during the first quarter of 2007, incurring no realized hedging gains or losses, and 52% of our oil

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volumes during the first quarter of 2006 incurring derivative settlement losses of $9.0 million. We hedged 62% of our gas volumes during the first quarter of 2007, incurring no realized hedging gains or losses and 58% of our gas volumes during the first quarter 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 April 1, 2007.

Lease Operating Expenses. Our lease operating expenses increased $4.7 million to $49.1 million in the first quarter of 2007 compared to the first quarter of 2006. Our lease operating expense as a percentage of oil and gas sales increased from 23% during the first quarter of 2006 to 31% during the first quarter of 2007. Our lease operating expenses per BOE increased from $12.09 during the first quarter of 2006 to $13.88 during the first quarter of 2007. The increase of 15% on a BOE basis was primarily caused by inflation in the cost of oil field goods and services, a high level of workover activity, and a change in labor billing practices. The cost of oil field goods and services increased due to a higher demand in the industry. Workovers amounted to $3.0 million in the first quarter of 2007, as compared to $2.1 million of workover activity in the first quarter of 2006. 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 general and administrative expense to us 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 the various taxing jurisdictions. Our production taxes for the first quarters of 2007 and 2006 were 6.0% and 6.3%, respectively, of oil and gas sales.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased $9.3 million to $44.6 million during the first quarter of 2007, as compared to the first quarter of 2006. On a BOE basis, our DD&A rate increased from $9.62 during the first quarter of 2006 to $12.62 in the first quarter of 2007. The primary factors causing this rate increase were higher drilling expenditures, downward oil and gas reserve revisions, and 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. Changes to the pricing environment can also impact our DD&A rate. Price increases allow for longer economic production lives and corresponding increased proved reserve quantities and, as a result, lower depletion rates. Price decreases have the opposite effect. The components of our DD&A expense were as follows (in thousands):

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	Three Months Ended March 31, 2007	2006
Depletion	$ 43,224	$ 34,221
Depreciation	740	531
Accretion of asset retirement obligations	607	548
Total	$ 44,571	$ 35,300

Exploration and Impairment Costs. Our exploration and impairment costs increased $2.1 million to $9.2 million in the first quarter of 2007 compared to the first quarter of 2006. The components of exploration and impairment costs were as follows (in thousands):

	Three Months Ended March 31, 2007	2006
Exploration	$ 6,860	$ 6,902
Impairment	2,316	140
Total	$ 9,176	$ 7,042

During the first quarter of 2007, we did not drill any exploratory dry holes, as compared to the first quarter of 2006, whereby we drilled one exploratory dry hole totaling $2.8 million. This reduction in exploratory dry hole expense was offset by an increase in geological and geophysical expenses during the first quarter of 2007. The impairment charge in 2007 and 2006 is related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of March 31, 2007, the amount of unproved properties being amortized increased by $39.5 million as a result of significant undeveloped acreage and unproved reserves purchased primarily during 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 March 31, 2007	2006
General and administrative expenses	$ 15,843	$ 14,119
Reimbursements and allocations	(7,558)	(4,508)
General and administrative expense, net	$ 8,285	$ 9,611

General and administrative expense before reimbursements and allocations increased $1.7 million to $15.8 million during the first quarter of 2007. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $1.3 million. The increase in reimbursements and allocations in the first 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

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our joint interest owners on properties we operate. Our general and administrative expenses remained consistent at 5% of oil and gas sales during the first quarter of 2006 compared to the first quarter of 2007.

Change in Production Participation Plan Liability. For the three months ended March 31, 2007, this non-cash expense remained consistent at $2.1 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 acquisitions, and employees' continued vesting in the Plan. During the three months ended March 31, 2007, the five-year average historical NYMEX prices used to estimate this liability increased $2.05 for crude oil and $0.30 for natural gas from December 31, 2006, as compared to increases of $1.25 for crude oil and $0.29 for natural gas for the three months ended March 31, 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 expenses were as follows (in thousands):

	Three Months Ended March 31,	
	2007	**2006**
Credit Agreement	$ 7,023	$ 4,115
Senior Subordinated Notes	11,180	11,010
Amortization of debt issue costs and debt discount	1,276	1,323
Accretion of tax sharing liability	380	525
Other	100	-
Capitalized interest	(462)	-
Total interest expense	$ 19,497	$ 16,973

The increase in interest expense was mainly due to additional borrowings outstanding in 2007 under our credit agreement. We also experienced higher weighted average interest rates on our debt during the first quarter of 2007.

Our weighted average debt outstanding during the first quarter of 2007 was $1,030.0 million versus $901.8 million in the first quarter of 2006. Our weighted average effective cash interest rate was 6.9% during the first quarter of 2007 versus 6.7% during the first 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 7.4% during the first quarter of 2007 and the first quarter of 2006.

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 within the specified time periods. We therefore reclassified the net loss 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 as of

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March 31, 2007. We also discontinued hedge accounting prospectively for these collars. During the first quarter of 2006, we did not recognize any unrealized derivative losses.

Income Tax Expense. Income tax expense totaled $5.9 million for the first quarter of 2007 and $20.3 million for the first quarter of 2006. Our effective income tax rate decreased from 38.1% for the first quarter 2006 to 35.4% for the first quarter of 2007 primarily due to a change in our state effective rate in the latter half of 2006.

Net Income. Net income decreased from $33.0 million during the first quarter of 2006 to $10.7 million during the first quarter of 2007. The primary reasons for this decrease included a 4% decrease in equivalent volumes sold, a 4% decrease in oil prices (net of hedging) and a 16% decrease in gas prices (net of hedging) between periods, higher lease operating expense, DD&A, exploration and impairment, interest expense and unrealized derivative loss. The decreased production and pricing and increased expenses were partially offset by lower production taxes and general and administrative expenses in the first quarter of 2007.

Liquidity and Capital Resources

Overview. At December 31, 2006, our debt to total capitalization ratio was 45.4%, we had $10.4 million of cash on hand and $1,186.7 million of stockholders' equity. At March 31, 2007, our debt to total capitalization ratio was 46.8%, we had $8.2 million of cash on hand and $1,192.9 million of stockholders' equity. In the first quarter of 2007, we generated $62.4 million of cash provided by operating activities, a decrease of $48.9 million over the same period in 2006. Cash provided by operating activities decreased primarily because of lower production and lower average sales prices for crude oil and natural gas as well as higher cash costs and expenses. We also generated $60.3 million from financing activities primarily consisting of $60.0 million in net borrowings against our credit agreement. Cash on hand and cash flows from operating and financing activities were primarily used to finance $109.4 million of drilling and development capital expenditures paid in the first quarter of 2007 and $16.7 million of cash acquisition capital expenditures to acquire the Parshall Prospect in North Dakota. The chart below details our drilling and development capital expenditures incurred by region during the first quarter of 2007 (in thousands).

	Drilling Capex	% of Total
Permian Basin	$ 36,289	31%
Rocky Mountains	36,212	31%
Mid-Continent	32,161	28%
Gulf Coast	7,464	7%
Michigan	3,703	3%
Total drilling and development capital expenditures incurred	115,829	100%
Increase in accrued capital expenditures	(6,427)	
Total drilling and development capital expenditures paid	$ 109,402	

We continually evaluate our capital needs and compare them to our capital resources. Our 2007 budgeted capital expenditures for the further development of our property base are $400.0 million, a decrease from the $455.0 million incurred on capitalized drilling and development during 2006. Although we have no specific budget for property acquisitions in 2007, we will continue to seek property acquisition opportunities that complement our existing core property base. We expect

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to fund our 2007 development expenditures from internally generated cash flow and cash on hand. We believe that should attractive acquisition opportunities arise or development expenditures exceed $400.0 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 capital 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.

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 March 31, 2007, had a borrowing base of $875.0 million with $440.0 million outstanding, leaving $435.0 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.

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 March 31, 2007, letters of credit totaling $0.3 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. As of March 31, 2007, the effective weighted average interest rate on the outstanding principal balance under the credit agreement was 6.7%.

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 (as defined in the credit agreement) ratio 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 March 31, 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

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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 Corporation's 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. In addition, Whiting Oil and Gas Corporation's credit agreement restricts the ability of our subsidiaries to make certain payments, including principal on the notes, to us. We were in compliance with these covenants as of March 31, 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.

Shelf Registration Statement. In May 2006, we filed a universal shelf registration statement with the SEC 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.

Tax Sharing Liability. In connection with our initial public offering in November 2003, we entered into a tax separation and indemnification agreement with our former parent, Alliant Energy Corporation ("Alliant Energy"). Pursuant to this agreement, we and Alliant Energy made a tax election with the effect that the tax bases of the assets of Whiting Oil and Gas Corporation and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. We have adjusted deferred taxes on our balance sheet to reflect the new tax bases of our assets. These additional 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

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December 31, 2013. Such tax benefits will generally be calculated by comparing our actual taxes to the taxes that would have been owed by us had the increase in bases not occurred. 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. We have estimated that total payments to Alliant will approximate $38.6 million on an undiscounted basis, with a present value of $26.2 million. During the first quarter of 2007, we did not make any payments under this agreement but did recognize $0.4 million of accretion expense, which is included as a component of interest expense. Our estimate of payments to be made under this agreement of $3.6 million in 2007 is reflected as a current liability at March 31, 2007.

Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of March 31, 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**	**2-3 years**	**4-5 years**	**More than 5 years**
Long-term debt (a)	$ 1,055,975	$ -	$ -	$ 440,000	$ 615,975
Cash interest expense on debt (b)	381,589	66,901	148,610	101,716	64,362
Asset retirement obligation (c)	40,347	612	1,121	2,990	35,624
Tax sharing liability (d)	27,552	3,565	5,988	5,044	12,955
Derivative contract liability fair value (e)	17,246	10,071	7,175	-	-
Purchasing obligations (f)	303,914	24,767	101,040	101,329	76,778
Drilling rig contracts (g)	43,342	16,936	23,994	2,412	-
Operating leases (h)	6,752	1,749	3,537	1,466	-
Total	$ 1,876,717	$ 124,601	$ 291,465	$ 654,957	$ 805,694

(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 6.7%.

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

(d)

Amounts shown are the estimated payments due based on projected future income tax benefits from the increase in tax bases described under "Tax Sharing Liability" above.

(e) We have entered into derivative contracts, primarily costless collars, to hedge our exposure to crude oil and natural gas price fluctuations. As of March 31, 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 entered into two take-or-pay purchase agreements, one agreement in July 2005 for 9.5 years and one agreement in March 2006 for 8 years, whereby we have committed to buy certain volumes of CO2 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 CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. The CO2 volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, we expect to avoid any payments for deficiencies.

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(g) We entered into three separate three-year agreements in 2005 for drilling rigs, a two-year agreement in February 2006 for a workover rig, and a three-year agreement in September 2006 for an additional drilling rig, all operating in the Rocky Mountains region. As of March 31, 2007, early termination of these contracts would have required maximum penalties of $30.2 million. No other drilling rigs working for us are currently under long-term contracts or contracts which 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 26,500 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.

Price-sharing Arrangement. As part of a 2002 purchase transaction, we agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2007 increased to 50% of the actual price received in excess of $20.98 per barrel. As of March 31, 2007, approximately 34,900 net barrels of crude oil per month (5% of March 2007 net crude oil production) are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. During the first quarter of 2007, we paid $1.8 million under this agreement. As of March 31, 2007, we have accrued an additional $0.5 million as currently payable.

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, and there were no additions or reductions to our unrecognized tax benefits during the three months ended March 31, 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.

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 quarter 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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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 April 1, 2007 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)	NYMEX Floor/Ceiling
Crude Oil	04/2007 to 06/2007	110,000	$50.00/$72.00
Crude Oil	04/2007 to 06/2007	300,000	$50.00/$78.50
Crude Oil	07/2007 to 09/2007	110,000	$50.00/$70.90
Crude Oil	07/2007 to 09/2007	300,000	$50.00/$77.55
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	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	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	10/2008 to 12/2008	110,000	$48.00/$70.20
Crude Oil	10/2008 to 12/2008	120,000	$60.00/$75.85

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases 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 $3.7 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 April

1, 2007 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	2007 Price Per MMBtu
Natural Gas	04/2007 to 05/2011	29,000	$4.75
Natural Gas	04/2007 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 the end of the quarter ended March 31, 2007. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Vice President and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of the end of the quarter ended March 31, 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 March 31, 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 1A. **Risk Factors**

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2006. No material change to such risk factors has occurred during the three months ended March 31, 2007.

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 27th day of April, 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)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for awards to executive officers on and after February 23, 2007.
(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.

* A management contract or compensatory plan or arrangement.