CREDO PETROLEUM CORP
Form 10-Q
March 11, 2008

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended January 31, 2008

o 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: 0-8877

CREDO PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Colorado	**84-0772991**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1801 Broadway, Suite 900, Denver, Colorado	**80202**

(Address of principal executive offices)	(Zip Code)

303-297-2200

(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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. (See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Act.)

Large accelerated filer o Accelerated filer x Non-accelerated filer o Smaller reporting company o

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock, net of treasury stock, as of the latest practicable date.

Date	**Class**	**Outstanding**
Mar.10, 2008	Common stock, $.10 par value	9,295,000

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

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Quarterly Report on Form 10-Q For the Period Ended January 31, 2008

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The terms CREDO , Company , we , our , and us refer to CREDO Petroleum Corporation and its subsidiaries unless the context suggests otherwise.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

		January 31, 2008 (Unaudited)		October 31, 2007
ASSETS				
Current Assets:				
Cash and cash equivalents	$	**5,708,000**	$	7,285,000
Short-term investments		**6,305,000**		6,383,000
Receivables:				
Accrued oil and gas sales		**2,219,000**		1,647,000
Trade		**694,000**		602,000
Derivative Assets		**127,000**		443,000
Other current assets		**145,000**		55,000
Total current assets		**15,198,000**		16,415,000
Long-term assets:				
Oil and gas properties, at cost, using full cost method:				
Unevaluated oil and gas properties		**9,593,000**		7,791,000
Evaluated oil and gas properties		**52,732,000**		51,691,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties		**(22,934,000)**		(22,108,000)
Net oil and gas properties, at cost, using full cost method		**39,391,000**		37,374,000
Exclusive license agreement, net of amortization of $519,000 in 2008 and $466,000 in 2007		**181,000**		198,000
Compressor and tubular inventory to be used in development		**1,066,000**		1,090,000
Other, net		**290,000**		272,000
Total assets	$	**56,126,000**	$	55,349,000
LIABILITIES AND STOCKHOLDERS EQUITY				
Current Liabilities:				
Accounts payable	$	**870,000**	$	1,639,000
Revenue distribution payable		**1,005,000**		979,000
Other accrued liabilities		**194,000**		852,000
Income taxes payable		**486,000**		434,000
Total current liabilities		**2,555,000**		3,904,000
Long Term Liabilities:				
Deferred income taxes, net		**9,718,000**		9,204,000
Exclusive license obligation, less current obligations of $77,000 in 2008 and $70,000 in 2007		**85,000**		85,000
Asset retirement obligation		**1,040,000**		1,016,000
Total liabilities		**13,398,000**		14,209,000
Commitments				

Stockholders Equity:				
Preferred stock, no par value, 5,000,000 shares authorized, none issued				
Common stock, $.10 par value, 20,000,000 shares authorized, 9,510,000 shares issued in 2008 and in 2007		**951,000**		951,000
Capital in excess of par value		**15,928,000**		15,913,000
Treasury stock at cost, 215,000 shares in 2008 and 2007		**(506,000)**		(506,000)
Accumulated other comprehensive income		**91,000**		319,000
Retained earnings		**26,264,000**		24,463,000
Total stockholders equity		**42,728,000**		41,140,000
Total liabilities and stockholders equity	**$**	**56,126,000**	$	55,349,000

The accompanying notes are an integral part of these consolidated financial statements.

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

Consolidated Statements of Operations

(Unaudited)

		Three Months Ended January 31, 2008		2007
REVENUES:				
Oil and gas sales	**$**	**4,580,000**	$	3,808,000
Investment income (loss) and other		**(5,000)**		247,000
		4,575,000		4,055,000
COSTS AND EXPENSES:				
Oil and gas production		**852,000**		913,000
Depreciation, depletion and amortization		**853,000**		958,000
General and administrative		**332,000**		278,000
Interest		**1,000**		6,000
		2,038,000		2,155,000
INCOME BEFORE INCOME TAXES		**2,537,000**		1,900,000
INCOME TAXES		**(736,000)**		(536,000)
NET INCOME	**$**	**1,801,000**	$	1,364,000
EARNINGS PER SHARE OF COMMON STOCK BASIC	**$**	**.19**	$	.15
EARNINGS PER SHARE OF COMMON STOCK DILUTED	**$**	**.19**	$	.15
Weighted average number of shares of Common Stock and dilutive securities:				
Basic		**9,295,000**		9,261,000
Diluted		**9,356,000**		9,387,000

The accompanying notes are an integral part of these consolidated financial statements.

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(Unaudited)

	Three Months Ended January 31, 2008		2007	
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$	**1,801,000**	$	1,364,000
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization		**853,000**		958,000
Deferred income taxes		**514,000**		328,000
(Gain) loss on short term investments		**78,000**		(231,000)
Compensation expense related to stock options granted		**15,000**		57,000
Other		**24,000**		3,000
Changes in operating assets and liabilities:				
Proceeds from short-term investments				719,000
Purchase of short-term investments				(1,000,000)
Accrued oil and gas sales		**(572,000)**		307,000
Trade receivables		**(92,000)**		(367,000)
Other current assets		**(2,000)**		(69,000)
Accounts payable and accrued liabilities		**(1,045,000)**		(629,000)
Income taxes payable		**52,000**		99,000
NET CASH PROVIDED BY OPERATING ACTIVITIES		**1,626,000**		1,539,000
CASH FLOWS FROM INVESTING ACTIVITIES:				
Additions to oil and gas properties		**(3,200,000)**		(3,005,000)
Changes in other long-term assets		**(3,000)**		(56,000)
NET CASH USED IN INVESTING ACTIVITIES		**(3,203,000)**		(3,061,000)
CASH FLOWS FROM FINANCING ACTIVITIES				
NET CASH PROVIDED BY FINANCING ACTIVITIES				
DECREASE IN CASH AND CASH EQUIVALENTS		**(1,577,000)**		(1,522,000)
CASH AND CASH EQUIVALENTS:				
Beginning of period		**7,285,000**		4,577,000
End of period	$	**5,708,000**	$	3,055,000
Supplemental cash flow information:				
Cash paid during the period for income taxes	$	**100,000**	$	
Additions to oil and gas properties in current liabilities	$	**356,000**	$	

The accompanying notes are an integral part of these consolidated financial statements.

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

Notes To Consolidated Financial Statements (Unaudited)

January 31, 2008

1. BASIS OF PRESENTATION

The accompanying unaudited consolidated financial statements have been prepared in accordance with U. S. generally accepted accounting principles for interim financial information and with the instructions for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by U. S. generally accepted accounting principles for complete financial statements. In the opinion of management, the consolidated financial statements contain all adjustments (consisting of normal recurring adjustments) considered necessary for a fair presentation of the company s results for the periods presented. These consolidated financial statements should be read in conjunction with the company s Annual Report on Form 10-K for the fiscal year ended October 31, 2007.

Certain 2007 amounts have been reclassified to conform to the current year presentation. Such reclassification had no effect on net income or shareholder equity.

2. SIGNIFICANT ACCOUNTING POLICIES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The company bases its estimates on historical experience and on various other assumptions it believes to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, the company believes that its estimates are reasonable and that actual results will not vary significantly from the estimated amounts, in the ordinary course of business.

3. STOCK-BASED COMPENSATION

The CREDO Petroleum Corporation 2007 Stock Option Plan (the 2007 Plan) is described in the Notes to Consolidated Financial Statements in the company s Annual Report on Form 10-K for the year ended October 31, 2007. No options have been granted under the 2007 Plan. The CREDO Petroleum Corporation 1997 Stock Option Plan (the 1997 Plan) expired on July 29, 2007. No additional options can be granted under the 1997 Plan. However, all outstanding options granted under the 1997 Plan will continue to be governed by the terms of that Plan.

For the three months ended January 31, 2008 and 2007, the company recognized stock based compensation expense of $15,000 ($11,000 net of tax) and $57,000 ($41,000 net of tax) respectively. The estimated unrecognized compensation cost from unvested stock options as of January 31, 2008 was approximately $108,000 which is expected to be recognized over an average of 2.3 years.

No options were granted during the three months ended January 31, 2008. The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes option pricing model. The weighted average assumptions used in the option pricing model for the three months ended January 31, 2007 were: volatility, 50.84%; expected option term, 2.5 years; risk-free interest rate, 4.58%; and expected dividend yield, 0%.

4. NATURAL GAS PRICE HEDGING

The company periodically hedges the price of a portion of its estimated natural gas production when the potential for significant downward price movement is anticipated. Hedging transactions typically take the form of forward short positions and collars on the NYMEX futures market, and are closed by purchasing offsetting positions. Such hedges, which are accounted for as cash flow hedges, do not exceed estimated production volumes, are expected to have reasonable correlation between price movements in the futures market and the cash markets where the company s production is located, and are authorized by the company s Board of Directors. Hedges are expected to be closed as related production occurs but may be closed earlier if the anticipated downward price movement occurs or if the company believes that the potential for such movement has abated.

The company recognizes all derivatives (consisting solely of cash flow hedges) on its balance sheet at fair value at the end of each period. Changes in the fair value of a cash flow hedge are recorded in Stockholders Equity as Accumulated Other Comprehensive Income on the Consolidated Balance Sheets and then are transferred into the Consolidated Statement of Operations as the underlying hedged item affects earnings. Amounts reclassified into earnings related to natural gas hedges are included in oil and gas sales.

Hedging gains and losses are recognized as adjustments to gas sales as the hedged product is produced. The company had hedging gains of $847,000 ($601,000 net of income tax) and $396,000 ($284,000 net of income tax) in the three months ended January 31, 2008 and 2007, respectively. Any hedge ineffectiveness, which was not material for any period, is immediately recognized in gas sales.

Open hedge contracts are indexed to the NYMEX. Periodically, the company enters into contracts indexed to Panhandle Eastern Pipeline Company for Texas, Oklahoma mainline. For comparative purposes, hedges indexed to Panhandle Eastern Pipeline Company are expressed on a NYMEX basis. For hedges indexed to Panhandle Eastern Pipeline Company, the individual month price (basis) differentials between the NYMEX and Panhandle Eastern Pipeline Company range from minus $1.45 in the winter months to minus $0.90 in the spring months.

Unrecognized gains and losses on hedge contracts at January 31, 2008 totaled a gain of $127,000 ($91,000 after income tax) and were included in Other Comprehensive Income . These contracts covered 1,420 MMBtus at average monthly NYMEX basis prices ranging from $7.83 to $9.42.

Subsequent to January 31, 2008, the company entered into additional hedge contracts covering 620 MMBtus at NYMEX basis prices, ranging from $8.13 to $9.95 for the production months of October 2008 through October 2009.

The company has a hedging line of credit with its bank which is available, at the discretion of the company, to meet margin calls. To date, the company has not used this facility and maintains it only as a precaution related to possible margin calls. The maximum credit line is $5,900,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the company s bank, and prohibits funded debt in excess of $500,000. It expires on November 15, 2010.

5. COMPREHENSIVE INCOME

Comprehensive income includes all changes in equity during a period except those resulting from investments by, and distributions to, stockholders. The components of comprehensive income for the three months ended January 31, 2008 and 2007 are as follows:

	Three Months Ended January 31,			
		2008		**2007**
Net income	**$**	**1,801,000**	$	1,364,000
Other comprehensive income:				
Change in fair value of derivatives		**(316,000)**		(371,000)
Income tax benefit		**88,000**		100,000
Total comprehensive income	**$**	**1,573,000**	$	1,093,000

6. EARNINGS PER SHARE

The company s calculation of earnings per share of common stock is as follows:

	Three Months Ended January 31,									
	2008					**2007**				
		Net Income	**Shares**		**Net Income Per Share**		Net Income	Shares		Net Income Per Share
Basic earnings per share	**$**	**1,801,000**	**9,295,000**	**$**	**.19**	$	1,364,000	9,261,000	$	.15
Effect of dilutive shares of common stock from stock options			**61,000**					126,000		(.00)
Diluted earnings per share	**$**	**1,801,000**	**9,356,000**	**$**	**.19**	$	1,346,000	9,387,000	$	.15

7. INCOME TAXES

The company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time.

The total future deferred income tax liability is extremely complicated for any energy company to estimate due in part to the long-lived nature of depleting oil and gas reserves and variables such as product prices. Accordingly, the liability is subject to continual recalculation, revision of the numerous estimates required, and may change significantly in the event of such things as major acquisitions, divestitures, product price changes, changes in reserve estimates, changes in reserve lives, and changes in tax rates or tax laws.

On November 1, 2007 the company adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). In implementing FIN 48, we found no significant uncertain tax positions. Our policy is to recognize potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. No interest and penalties related to uncertain tax positions were accrued at January 31, 2008

We have not had any material changes to our unrecognized tax benefits since adoption, nor do we anticipate significant changes to the total amount of unrecognized tax benefits within the next twelve months.

As of January 31, 2008 we remain subject to examination of our Federal and state tax returns, except Colorado, for the tax years 2004 through 2006, and for the tax years 2003 through 2006 for our Colorado tax returns.

8. COMMITMENTS

The company has no material outstanding commitments at January 31, 2008.

9. RECENT ACCOUNTING PRONOUNCEMENTS

In July 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48).* This interpretation clarifies the application of SFAS 109 by defining the criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise s financial statements and also provides guidance on measurement, de-recognition, classification, interest and penalties, accounting in interim periods and disclosure. The company adopted FIN 48 November 1, 2007.

In November 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combination* (FAS 141(R)) and SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (FAS 160). FAS 141(R) will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. FAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. FAS 141(R) and FAS 160 are effective for both public and private companies for fiscal years beginning on or after December 15, 2008 (fiscal 2010 for the Company). FAS 141(R) will be applied prospectively. FAS 160 requires retroactive adoption of the presentation and disclosure requirements for existing minority interests. All other requirements of FAS 160 will be applied prospectively. Early adoption is prohibited for both standards. Management is currently evaluating the requirements of FAS 141(R) and FAS 160 and has not yet determined the impact on its financial statements.

In December 2007, the FASB issued SFAS No.157*, Fair Value Measurements*. This Statement does not require any new fair value measurements, but rather, it provides enhanced guidance to other pronouncements that require or permit assets or liabilities to be measured at fair value. However, the application of this Statement may change how fair value is determined. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. As of December 1, 2007 the FASB has proposed a one-year deferral for the implementation of the Statement for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. Management is currently evaluating the requirements of FAS 159 and has not yet determined the impact on its financial statements.

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q includes certain statements that may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements included in this Quarterly Report on Form 10-Q, other than statements of historical facts, address matters that the company reasonably expects, believes or anticipates will or may occur in the future. Forward-looking statements may relate to, among other things:

- the company s future financial position, including working capital and anticipated cash flow;
- amounts and nature of future capital expenditures;
- operating costs and other expenses;
- wells to be drilled or reworked;
- oil and natural gas prices and demand;
- existing fields, wells and prospects;
- diversification of exploration;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development and drilling potential;
- expansion and other development trends in the oil and natural gas industry;
- the company s business strategy;
- production of oil and natural gas;
- matters related to the Calliope Gas Recovery System;
- effects of federal, state and local regulation;
- insurance coverage;
- employee relations;

- investment strategy and risk; and
- expansion and growth of the company s business and operations.

LIQUIDITY AND CAPITAL RESOURCES

At January 31, 2008, working capital increased $3,192,000, or 34% to $12,643,000 compared to $9,451,000 at January 31, 2007. For the three months ended January 31, 2008, net cash provided by operating activities increased $87,000, or 6%, to $1,626,000 compared to net cash provided by operating activities of $1,539,000 for the same period in 2007. Net income increased $437,000 primarily due to an increase in revenues of $520,000, and a decrease in total costs and expenses of $117,000, offset by an increase in income taxes of $200,000.

For the three months ended January 31, 2008 and 2007, net cash used in investing activities was $3,203,000 and $3,061,000, respectively. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $2,844,000 and $3,005,000 respectively.

The average return on the company s investments was a loss of 1.2% for the three months ended January 31, 2008 compared to 4.5% return for the same period last year. At January 31, 2008, approximately 46% of the investments were directly invested in mutual funds and were managed by professional money managers. Remaining investments are in managed partnerships (generally known as hedge funds) that use various strategies to minimize their correlation to stock market movements. Most of the investments are highly liquid and the company believes they represent a responsible approach to cash management. In the company s opinion, the greatest investment risk is the potential for negative market impact from unexpected, major adverse news.

Existing working capital and anticipated cash flow are expected to be sufficient to fund operations and capital commitments for at least the next 12 months. At January 31, 2008, the company had no lines of credit or other bank financing arrangements except for the hedging line of credit discussed in Note 4. Because earnings are anticipated to be reinvested in operations, cash dividends are not expected to be paid. The company has no defined benefit plans and no obligations for post retirement employee benefits.

The company s earnings before interest, taxes, depreciation, depletion and amortization, (EBITDA) increased to $3,391,000 for the three months ended January 31, 2008 from $2,864,000 for the three months ended January 31, 2007. EBITDA is not a GAAP measure of operating performance. The company uses this non-GAAP performance measure primarily to compare its performance with other companies in the industry that make a similar disclosure. The company believes that this performance measure may also be useful to investors for the same purpose. Investors should not consider this measure in isolation or as a substitute for operating income, or any other measure for determining the company s operating performance that is calculated in accordance with GAAP. In addition, because EBITDA is not a GAAP measure, it may not necessarily be comparable to similarly titled measures employed by other companies. A reconciliation between EBITDA and net income is provided in the table below:

	Three Months Ended January 31, 2008		2007	
RECONCILIATION OF EBITDA:				
Net Income	**$**	**1,801,000**	$	1,364,000
Add Back:				
Interest Expense		**1,000**		6,000
Income Tax Expense		**736,000**		536,000
Depreciation, Depletion and Amortization Expense		**853,000**		958,000
EBITDA	**$**	**3,391,000**	$	2,864,000

OFF-BALANCE SHEET FINANCING

The company has no significant off-balance sheet financing arrangements at January 31, 2008.

PRODUCT PRICES AND PRODUCTION

Although product prices are key to the company s ability to operate profitably and to budget capital expenditures, they are beyond the company s control and are difficult to predict. Since 1991, the company has periodically hedged the price of a portion of its estimated natural gas production when the potential for significant downward price movement is anticipated. Hedging transactions typically take the form of forward short positions, swaps and collars which are executed on the NYMEX futures market or by indexing to regional index prices associated with pipelines in proximity to the company s production. The company s current hedges are indexed to NYMEX. Refer to Note 4 of the Consolidated Financial Statements for a complete discussion on the company s hedging activities.

3. STOCK-BASED COMPENSATION

Gas and oil sales volume and price realization comparisons for the indicated periods are set forth below. Price realizations include the sales price and the effect of hedging transactions.

	Three Months Ended January 31,					
	2008		2007		Change%	
Product	Volume	Price	Volume	Price	Volume	Price
Gas (Mcf)	**392,000**	**$ 8.24(1)**	528,000	$ 6.03(2)	-26%	+37%
Oil (bbls)	**15,700**	**$ 86.39**	11,900	$ 52.06	+31%	+66%

(1) Includes $2.16 per Mcf hedging gain.

(2) Includes $0.75 per Mcf hedging gain.

OPERATIONS

During the first quarter of fiscal 2008, the company s operations continued to focus on its two core projects natural gas drilling and application of its patented Calliope Gas Recovery System.

The company believes that, in combination, its drilling and Calliope projects provide an excellent (and possibly unique) balance for achieving its goal of adding long-lived natural gas reserves and production at reasonable costs and risks. However, it should be expected that successful results will occur unevenly for both the drilling and Calliope projects. Drilling results are dependent on both the timing of drilling and on the drilling success rate. Calliope results are primarily dependent on the timing, volume and quality of Calliope installations available to the company.

The company will continue to actively pursue adding reserves through its two core projects in fiscal 2008, and expects these activities to be a reliable source of reserve additions. However, the timing and extent of such activities can be dependent on many factors which are beyond the company s control, including but not limited to, the availability, cost and quality of oil field services such as drilling rigs, production equipment and related services, and access to wells for application of the company s patented gas recovery system on low pressure gas wells. The prevailing price of oil and natural gas has a significant effect on demand and, thus, the related cost of such services and wells.

The cost of field services, particularly the cost of drilling wells, has increased dramatically during the past several years, driven by higher energy prices. Concurrently, the quality of field services has diminished markedly due to manpower shortages. The combination of much higher field service costs and degradation in the quality of the services is having a material negative impact on drilling economics. Accordingly, the company continues to high-grade its drilling prospects, and in some cases postpone less robust projects pending improvement in the field services sector. In the short term, this will reduce the number of drilling prospects which may, in turn, impede the growth of the company s production and reserves.

The company is currently experiencing delays in securing drilling rigs and delivery of production equipment, primarily compressors and coil tubing. These delays are extending the time it takes the company to conduct its field operations. As a result, the company could be at risk for price increases related to these types of services and equipment.

All of the company s oil and natural gas properties are located on-shore in the continental United States. The company s future drilling activities may not be successful, and its overall drilling success rate may change. Unsuccessful drilling activities could have a material adverse effect on the company s results of operations and financial condition. Also, the company may not be able to obtain the right to drill in areas where it believes there is significant potential for the company.

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3. STOCK-BASED COMPENSATION

Drilling Activities.

<u>Northern Anadarko Basin</u> The company owns a significant inventory of acreage (approximately 70,000 gross acres) located along the northern portion of the Anadarko Basin where it conducts an active drilling program. Wells generally target the Morrow, Oswego and Chester formations between 7,000 and 11,000 feet. The company expects to drill a substantial number of additional wells on this acreage.

In Hemphill County, Texas, the 11,200-foot wildcat well drilled in fiscal 2007 to test the 3,780 gross acre Humphreys Prospect encountered excellent quality Morrow sands, and tested at the rate of 3.0 MMcf per day. However, production declined rapidly but stabilized at 150 Mcf per day. The stabilized production rate suggests that the first well is indirectly connected to a larger Morrow reservoir. The company subsequently purchased and reprocessed 3-D seismic over the prospect, and believes that it has identified the primary Morrow channel. A second well was drilled in January 2008 to test the seismic interpretation. That well encountered Tonkawa and Cherokee sands that appear to be productive based on drilling data and electric logs, but it did not encounter the high potential Morrow sands. The well is currently awaiting completion for production. The company owns a 25% working interest. Additional drilling is expected on the prospect.

In Canadian County, Oklahoma, the 640 gross acre Loosen Prospect continues to yield excellent drilling results from the Redfork and Skinner formations. The 11,500-foot Marcia #1-14 was recently drilled and encountered Skinner and Mississippi sands. The well is currently awaiting completion and pipeline connection. The Marcia well is a north extension to the recently completed Chappell well which encountered pay zones in five separate formations. The well is currently completed in three of the five zones and is producing 1.9 MMcf and 30 barrels of oil per day. The remaining zones will be opened for production at a later date. The Chappell well was a north extension to the Hazel well, drilled in December 2006, which is still producing 2.0 MMcf (million cubic feet of gas) and about 20 barrels of oil per day. The company owns working interests in the new wells as follows: Hazel - 6.25%; Chappell - 16.3%, Marcia - 14.5%.

In Harper County, Oklahoma, the 3,840 gross acre Buffalo Creek Prospect continues to be a very active drilling area for the company based on a recently completed 3-D seismic program. Nine wells have now been completed on the prospect with production from the Chester, Morrow and Oswego formations. The most recent well encountered 14 feet of excellent Morrow sand porosity, however, production testing has indicated that the reservoir is extremely limited in size. The company owns working interests in the prospect ranging from 31% to 37%. Three to five new drilling locations are currently planned for 2008, and more are expected based on the results of future wells.

In Ellis County, Oklahoma, the first well was drilled on the company s 3,200 gross acre North Boxer Prospect. The 8,500-foot well is currently classified as a tight hole , meaning information is not being released for proprietary business reasons. A second wildcat well drilled about one mile to the south was completed but produced water from the objective sand. Two additional wells are currently being readied for drilling. The company owns working interests in the prospect ranging from 30% to 40%.

In Kingfisher County, Oklahoma, the first two wells have been drilled on the 1,280 gross acre Okarche Prospect to test the Hunton, Meramec, Chester and Redfork formations. The wells are each currently producing 200 Mcf and 10 barrels of oil per day. The company owns working interests ranging from 9.5% to 11%.

In Carter County, Oklahoma, the Southeast Hewitt Deese Sand Waterflood Unit has produced over 600,000 incremental barrels of oil, and continues to significantly outperform initial expectations. As a result of development drilling, production from the unit has recently increased about 40% to 270 barrels of oil per day. Further development is under consideration. The company owns a 17% working interest.

In Love County, Oklahoma, a new Deese sand waterflood project is currently in the approval process. The company owns a 10% to 12% working interest in various phases of the project.

South Texas The company s South Texas drilling projects diversify it exploration geographically, scientifically, and in terms of capital, risk and reserve potential. Compared to the company s Oklahoma drilling, the South Texas project involves higher costs and greater risks but offers significantly higher per well production and reserve potential.

The most significant of the company s two South Texas projects is 3-D seismic driven and focuses on the Vicksburg, Frio and Queen City sands in Hidalgo County and the Wilcox sands in Jim Hogg County at depths ranging from 7,200 feet to 17,500 feet. To date, the company has invested approximately $1,900,000 (net) in the project, exclusive of drilling. Prior to sale or farmout of the prospects, the company owns a 75% interest before recovery of its investment, exclusive of drilling, and 37.5% thereafter. The company has the option to participate in drilling any of the prospects for its full interest or to reduce its costs and risks by selling or farming-out its interest to third parties in return for cash consideration and a carried interest on the initial wildcat well(s).

The primary objective of this project has been identification, leasing and sale of three deep Wilcox prospects located in Jim Hogg County. The prospects cover about 3,600 gross acres, range in depth from 16,500 to 17,500 feet, and are located in an area where several nearby fields have produced hundreds of billions of cubic feet of gas from the Wilcox formation. The company s 3-D seismic interpretation indicates that the prospects are large enough in size to have very substantial production and reserve potential in relation to the company s existing production and reserves. However, the prospects are high risk, rank wildcat prospects and per well drilling costs far exceed those normally incurred by the company. Therefore, the company has elected to sell a portion of its interest for cash consideration and a carried interest on two initial wildcat wells. Third parties have committed to purchase the three prospects and to drill a wildcat well on one prospect. The second wildcat well is optional based on the outcome of the first well. Paperwork is in the process of being completed. The Operator has indicated the intent to commence drilling early in 2008. In addition to recovering a significant portion its cash investment in the project and being carried for an interest in the initial test well(s), the company has preserved its option to participate in other wells drilled on the prospects with interests ranging from 11.25% before recovery of its investment to 5.625% after recovery. If drilling is successful, the company expects that its retained interest in the prospects will have a very significant impact on its production and reserve growth.

Elsewhere in South Texas, the first well has been drilled on the 2,500 gross acre Briggs Ranch Prospect located in Victoria County. The prospect is fault separated from the Heyser Field which has produced 738,000 barrels of oil and 17 Bcf from the Frio sands. The 8,600-foot Briggs Ranch #1 encountered 11 feet of Frio sands and is currently producing about 1.0 MMcf per day. The company owns a 9% working interest.

North-Central Kansas The company s Central Kansas drilling project provides additional diversification to the company s drilling program through the use of 3-D seismic to identify shallow oil prospects. The acreage is located in prolific oil producing areas where 3-D seismic has proven effective in identifying satellite structures near mature producing fields. Higher oil prices have justified using 3-D seismic technology to locate undrilled structures that are very difficult to find with old technology. Drilling targets the Lansing-Kansas City and Arbuckle formations at about 4,000 feet and, compared to the company s Northern Anadarko Basin and South Texas projects, is relatively low cost, low risk, and exclusively targets oil reserves in an effort to bring better product balance to the company s reserve base. Thus far, the company has assembled four separate drilling projects which encompass about 41,000 gross acres and is continuing to seek opportunities to increase its exposure to the play. The company owns working interests in the existing prospects ranging from 12.5% to 75%.

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The company s recent drilling results have improved dramatically as it continues to find the keys to successful seismic and geologic interpretation. Four of the last seven wells have been completed as producers, and three of those appear to be outstanding wells.

In Graham County, two of the first three wells on the 3,280 gross acre White Anticline and Mt. Vernon prospects resulted in Lansing Kansas City formation discoveries. Five additional wells have been approved for drilling. The company owns a 12.5% working interest in both prospects.

In Rawlins County, seismic is scheduled to commence shortly on the company s 3,560 gross acre Beaver Jenks prospect. The company owns a 30% working interest in the prospect.

In Sheridan County, three of the last six wells have resulted in discoveries on the company s 8,000 gross acre Lucerne Prospect. Three additional wells have been approved for drilling. The company owns a 30% working interest in the prospect.

In Barton and Rice Counties, seismic is scheduled to commence shortly on the company s 7,000 net acre prospect. The company owns a 75% working interest in the prospect.

Calliope Gas Recovery Technology

The company owns the exclusive right to a patented technology known as the Calliope Gas Recovery System. There are currently three U.S. patents and two Canadian patents related to the technology. One additional patent that mirrors the U.S. patents has been applied for in Canada. Calliope systems are installed on wells located in Oklahoma, Texas and Louisiana.

Calliope can achieve substantially lower flowing bottom-hole pressure than other production methods because it does not rely on reservoir pressure to lift liquids. In many reservoirs, lower bottom-hole pressure can translate into recovery of substantial additional natural gas reserves.

Calliope has proven to be reliable and flexible over a wide range of applications on wells the company owns and operates. It has also proven to be consistently successful. Accordingly, the company is implementing strategies designed to expand the population of wells on which it can install Calliope.

Calliope s Track Record Calliope wells are located in Oklahoma, Texas, and Louisiana and produce from both sandstone and carbonate reservoirs, including the Chester, Cotton Valley, Edwards, Hart, Hunton, Morrow, Nodosaria, Redfork and Springer formations. The Calliope wells range in depth from 6,400 to 18,400 feet. These wells represent rigorous applications for Calliope because at the time Calliope was installed, 14 of the wells were dead (an average of two to three years), nine were uneconomic and two were marginal. In addition, prior to the time Calliope was installed, many of the reservoirs were damaged by the parting shots of previous operators. Twenty-three of the wells were acquired from other operators after the operators had given-up on these wells. The previous operators were mostly medium to large independent oil and gas companies.

Initial Calliope production rates range up to 650 Mcfd and average per well Calliope reserves for non-experimental wells are estimated to be 1.0 Bcf. One of the company s early Calliope installations, the J.C. Carroll well, has now produced over a billion cubic feet of gas using Calliope.

The 25 Calliope installed applications are grouped into two categories experimental wells and non-experimental wells, also referred to as go-forward applications. Eleven of the 25 wells are experimental applications and 14 are go-forward applications. Experimental wells generally represent the first experimental application of a Calliope configuration in a wellbore. For example, the first installation of Calliope inside a particular tubing size is classified as an experimental application.

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Calliope has achieved compelling results on these less than ideal wells as is shown in the table below. For example, the entire group of 14 non-experimental wells were producing a total of only 88 Mcfd when Calliope was installed. Without Calliope, the wells represented a substantial plugging liability. However, with Calliope, those same 14 wells have now produced an incremental 3.4 Bcfe to date, and they are still producing about 2.0 MMcfed. With Calliope, the 14 wells were projected to have estimated ultimate incremental Calliope reserves totaling 13.6 Bcfe.

Group	**No. of Wells**	**Average Calliope Reserves Per Well (Bcfe)**	**Total Calliope Production to Date (Bcfe)**	**Total Projected Calliope Reserves (Bcfe)**
Non-Experimental Wells	**14**	**1.0**	**3.4**	**13.6**
Experimental Wells	11	0.2	0.6	1.4
All Wells	25	0.6	4.0	15.0

Calliope has proven to be a low risk and low cost liquid lift technology. Calliope has never failed to lift the liquids out of a wellbore. The average cost of a Calliope system is $400,000 for a 12,000-foot application. Based on average per well Calliope reserves of 1.0 Bcfe for go-forward applications, cost of Calliope in terms of units of natural gas reserves added is low compared to industry averages. Based on current natural gas prices, Calliope can economically be installed on wells which will yield significantly less than 1.0 Bcf of Calliope reserves. This will enable the company to significantly expand the range of Calliope applications to include many low permeability reservoirs, possibly including those in shale and other resource plays .

Realizing Calliope s value continues to be one of the company s top priorities. The company has been focused on three fronts to increase the number of Calliope installations: expanding the geographic region for purchasing Calliope candidate wells from third parties, joint ventures with larger companies, and drilling wells into low-pressure gas reservoirs for the purpose of using Calliope to recover stranded natural gas reserves.

Purchasing Calliope Candidate Wells Calliope operations were expanded into Texas and Louisiana in fiscal 2006. The company considers Texas and Louisiana to be very fertile areas for Calliope and has retained personnel and opened a Houston office to focus exclusively on purchasing wells for Calliope and on Calliope joint ventures.

In general, higher natural gas prices have made it increasingly difficult for the company to purchase wells for its Calliope system. In addition, higher gas prices have provided the incentive for other companies to perform high risk procedures (parting shots) in an attempt to revive wells prior to abandoning or selling the wells. These parting shots often result in severe reservoir damage that renders wells unsuitable for Calliope. Accordingly, viable Calliope candidate wells available to be purchased by the company have been very restricted.

Joint Ventures With Third Parties In an effort to increase the number of Calliope installations, the company has been discussing joint ventures with larger companies. Presentations have been made to a select group of companies, including majors and large independents. All of the companies have expressed an interest in Calliope. Two joint venture agreements were completed during 2007. Another joint venture agreement was completed in the first quarter of 2008. Joint venture discussions are in progress with a number of the companies, including evaluation of candidate wells.

The joint venture negotiation process has taken longer than expected because there are many decision points within large companies that cause delays. Nevertheless, the company continues to dedicate substantial resources to joint venture projects, as it believes that the company will eventually be successful in the joint venture area.

Calliope Drilling Project The company believes that there is a huge amount of gas stranded in abandoned and low pressure reservoirs that can be recovered using Calliope. It believes drilling new wells for Calliope into such reservoirs will provide a repeatable opportunity to lease large areas for systematic re-development. In addition, new wells allow optimum casing and tubular sizes to be installed which will substantially improve reserves and production compared to installing Calliope on existing wells where undersized tubulars often restrict Calliope s optimum performance.

In June 2007, the company entered into a joint venture to purchase an 11,000-foot well located in East Texas. The previous operator drilled the well and encountered low reservoir pressure. After unsuccessful attempts to make the well produce, the operator sold the well to the company joint venture for $65,000 (salvage value). Calliope was installed and immediately brought the well to life, producing at the rate of 250 Mcf per day. The well provided a successful test of the Calliope drilling concept and demonstrated that Calliope will successfully solve liquid loading problems that are difficult, if not impossible, to address with other liquid lift technologies.

Results of Operations

Three Months Ended January 31, 2008 Compared to Three Months Ended January 31, 2007

For the three months ended January 31, 2008, total revenues grew 13% to $4,575,000 compared to $4,055,000 during the same period last year. As the oil and gas price/volume table on page 12 shows, total gas price realizations, which reflect hedging transactions, increased 37% to $8.24 per Mcf and oil price realizations increased 66% to $86.39 per barrel. The net effect of these price changes was to increase oil and gas sales by $1,282,000. For the three months ended January 31, 2008, the company s gas equivalent production fell 19% resulting in an oil and gas sales decrease of $510,000. Investment and other income decreased $252,000 primarily due to performance of the company s investments, compared to last year.

For the three months ended January 31, 2008, total costs and expenses fell 5% to $2,038,000 compared to $2,155,000 for the comparable period in 2007. Oil and gas production expenses fell due primarily to a decrease in production taxes and a decrease in lease operating expenses related to several major workovers in 2007. DD&A declined primarily due to lower production partially offset by an increase in the amortizable cost base. General and administrative expenses increased primarily due to accounting and professional fees. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 29.0% and 28.2% for the 2008 and 2007 periods, respectively.

SIGNIFICANT ACCOUNTING POLICIES

The company believes the following accounting policies and estimates are critical in the preparation of its consolidated financial statements: the carrying value of its oil and natural gas properties, the accounting for oil and gas reserves, and the estimate of its asset retirement obligations.

OIL AND GAS PROPERTIES. The company uses the full cost method of accounting for costs related to its oil and natural gas properties. Capitalized costs included in the full cost pool are depleted on an aggregate basis using the units-of-production method. Depreciation, depletion and amortization is a significant component of oil and natural gas properties. A change in proved reserves without a corresponding change in capitalized costs will cause the depletion rate to increase or decrease.

Both the volume of proved reserves and any estimated future expenditures used for the depletion calculation are based on estimates such as those described under Oil and Gas Reserves below.

The capitalized costs in the full cost pool are subject to a quarterly ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10 percent plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower depreciation and depletion in future periods. A write-down may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the ceiling.

The company has made only one ceiling write-down in its 28-year history. That write down was made in 1986 after oil prices fell 51% and natural gas prices fell 45% between fiscal year end 1985 and 1986.

Changes in oil and natural gas prices have historically had the most significant impact on the company s ceiling test. In general, the ceiling is lower when prices are lower. Even though oil and natural gas prices can be highly volatile over weeks and even days, the ceiling calculation dictates that prices in effect as of the last day of the test period be used and held constant. The resulting valuation is a snapshot as of that day and, thus, is generally not indicative of a true fair value that would be placed on the company s reserves by the company or by an independent third party. Therefore, the future net revenues associated with the estimated proved reserves are not based on the company s assessment of future prices or costs, but rather are based on prices and costs in effect as of the end the test period.

OIL AND GAS RESERVES. The determination of depreciation and depletion expense as well as ceiling test write-downs related to the recorded value of the company s oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves. Oil and natural gas reserves include proved reserves that represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their values, including many factors beyond the company s control. Accordingly, reserve estimates are often different from the quantities of oil and natural gas ultimately recovered and the corresponding lifting costs associated with the recovery of these reserves.

ASSET RETIREMENT OBLIGATIONS. The company estimates the future cost of asset retirement obligations, discounts that cost to its present value, and records a corresponding asset and liability in its Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including future abandonment costs, inflation, market risk premiums, useful life, and cost of capital. The nature of these estimates requires the company to make judgments based on historical experience and future expectations. Revisions to the estimates may be required based on such things as changes to cost estimates or the timing of future cash outlays. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis.

REVENUE RECOGNITION. The company derives its revenue primarily from the sale of produced natural gas and crude oil. The company reports revenue gross for the amounts received before taking into account production taxes and transportation costs which are reported as oil and gas production expenses. Revenue is recorded in the month production is delivered to the purchaser at which time title changes hands. The company makes estimates of the amount of production delivered to purchasers and the prices it will receive. The company uses its knowledge of its properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices, and other factors as the basis for these estimates. Variances between estimates and the actual amounts received are recorded when payment is received.

A majority of the company s sales are made under contractual arrangements with terms that are considered to be usual and customary in the oil and gas industry. The contracts are for periods of up to five years with prices determined based upon a percentage of a pre-determined and published monthly index price. The terms of these contracts have not had an effect on how the company recognizes its revenue.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The company manages exposure to commodity price fluctuations by periodically hedging a portion of expected production through the use of derivatives, typically collars and forward short positions in the NYMEX or other regional indexes futures market. See Note 4 for more information on the company s hedging activities.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management evaluated, with the participation and under the supervision of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure and that such information is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during our last fiscal quarter that has materially affected or is reasonably likely to materially affect our internal control over financial reporting, except as follows: In Item 9A, Management s Report on Internal Control over Financial Reporting included in our Annual Report on Form 10-K for the year ended October 31, 2007 we reported a material weakness in the company s internal control. During the first quarter of fiscal 2008 management designed and implemented enhanced and accelerated training for its senior financial staff and hired an expert consultant to assist with review and financial statement disclosure. Management has not completed all of the testing of internal controls in these areas for fiscal 2008.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

None.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors previously disclosed in the company s Annual Report on Form 10-K for the fiscal year ended October 31, 2007.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibits are as follow:

31.1 Certification by Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002

31.2 Certification by Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002

32.1 Certification by Chief Executive Officer and Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act (18 U.S.C. Section 1350)

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.

CREDO Petroleum Corporation
(Registrant)

By:	/s/ James T. Huffman James T. Huffman President and Chief Executive Officer (Principal Executive Officer)
By:	/s/ David E. Dennis David E. Dennis Chief Financial Officer (Principal Financial and Accounting Officer)

Date: March 10, 2008