CREDO PETROLEUM CORP
Form 10-Q
September 14, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q

(Mark One)

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

For the quarterly period ended July 31, 2006

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 o No þ

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 o Non-accelerated filer þ

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

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
Sept. 8, 2006	Common stock, $.10 par value	9,247,646

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Quarterly Report on Form 10-Q For the Period Ended July 31, 2006
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The terms CREDO , Company , we , our , and us refer to CREDO Petroleum Corporation and its subsidiaries unles context suggests otherwise.

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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

Consolidated Balance Sheets

	July 31, 2006 (Unaudited)	October 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 3,784,000**	$ 1,935,000
Short-term investments	**5,858,000**	5,495,000
Receivables:		
Accrued oil and gas sales	**2,118,000**	2,776,000
Trade	**1,126,000**	1,003,000
Other current assets	**215,000**	245,000
Total current assets	**13,101,000**	11,454,000
Long-term assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	**5,268,000**	3,452,000
Evaluated oil and gas properties	**42,535,000**	36,121,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	**(17,507,000)**	(15,022,000)
Net oil and gas properties, at cost, using full cost method	**30,296,000**	24,551,000
Exclusive license agreement, net of amortization of $414,000 in 2006 and $361,000 in 2005	**285,000**	338,000
Compressor and tubular inventory to be used in development	**1,298,000**	1,288,000
Other assets	**200,000**	213,000
Total assets	**$ 45,180,000**	$ 37,844,000
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 4,049,000**	$ 3,426,000
Income taxes payable	**132,000**	331,000
Total current liabilities	**4,181,000**	3,757,000

Long Term Liabilities:		
Deferred income taxes, net	**7,387,000**	5,978,000
Exclusive license obligation, less current obligations of $64,000 in 2006 and 2005	**233,000**	233,000
Asset retirement obligation	**832,000**	929,000
Total liabilities	**12,633,000**	10,897,000
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 2006 and 2005	**951,000**	951,000
Capital in excess of par value	**14,729,000**	13,933,000
Treasury stock, 263,000 shares in 2006 and 279,000 in 2005		(125,000)
Accumulated other comprehensive income (loss)		(306,000)
Retained earnings, net of $6,272,000 related to 20% stock dividend in 2003	**16,867,000**	12,494,000
Total stockholders equity	**32,547,000**	26,947,000
Total liabilities and stockholders equity	**$ 45,180,000**	$ 37,844,000

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

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations
(Unaudited)

	Nine Months Ended July 31,		Three Months Ended July 31,	
	2006	2005	**2006**	2005
REVENUES:				
Oil and gas sales	**$ 11,809,000**	$ 8,785,000	**$ 3,966,000**	$ 3,396,000
Investment income and other	**446,000**	201,000	**3,000**	105,000
	12,255,000	8,986,000	**3,969,000**	3,501,000
COSTS AND EXPENSES:				
Oil and gas production	**2,604,000**	1,920,000	**861,000**	790,000
Depreciation, depletion and amortization	**2,568,000**	1,610,000	**939,000**	568,000
General and administrative	**940,000**	782,000	**361,000**	242,000
Interest	**27,000**	28,000	**9,000**	9,000
	6,139,000	4,340,000	**2,170,000**	1,609,000
INCOME BEFORE INCOME TAXES	**6,116,000**	4,646,000	**1,799,000**	1,892,000
INCOME TAXES	**(1,743,000)**	(1,301,000)	**(513,000)**	(530,000)
NET INCOME	**$ 4,373,000**	$ 3,345,000	**$ 1,286,000**	$ 1,362,000
EARNINGS PER SHARE OF COMMON STOCK BASIC	**$ .48**	$ .37	**$ .14**	$ .15
EARNINGS PER SHARE OF COMMON STOCK DILUTED	**$ .46**	$ .36	**$ .14**	$ .15
Weighted average number of shares of Common Stock and dilutive securities:				
Basic	**9,191,000**	9,069,000	**9,231,000**	9,087,000
Diluted	**9,512,000**	9,331,000	**9,498,000**	9,339,000

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

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Statement of Stockholders Equity and Comprehensive Income (Loss)
(Unaudited)
For the Nine Months Ended July 31, 2006

	Common Stock Shares	Common Stock Amount	Capital In Excess Of Par Value	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Comprehensive Income	Retained Earnings	Total Stockholders Equity
Balance, October 31, 2005	9,510,000	$ 951,000	$ 13,933,000	$ (125,000)	$ (306,000)		$ 12,494,000	$ 26,947,000
Comprehensive income:								
Net income						$ 4,373,000	4,373,000	4,373,000
Other comprehensive income:								
Change in fair value of derivatives, net of tax					306,000	306,000		306,000
Total comprehensive income						$ 4,679,000		
Exercise of common stock options			631,000	125,000				756,000
Compensation expense associated with unvested portion of previously granted stock options			165,000					165,000
Balance, July 31, 2006	9,510,000	$ 951,000	$ 14,729,000	$	$		$ 16,867,000	$ 32,547,000

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

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended July 31, 2006	Nine Months Ended July 31, 2005
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	**$ 4,373,000**	$ 3,345,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**2,568,000**	1,610,000
Deferred income taxes	**1,409,000**	1,250,000
Compensation expense related to stock options granted	**165,000**	217,000
Other	**(98,000)**	76,000
Changes in operating assets and liabilities:		
Proceeds from short-term investments	**193,000**	2,500,000
Purchase of short-term investments	**(556,000)**	(1,641,000)
Accrued oil and gas sales	**658,000**	(759,000)
Trade receivables	**(123,000)**	663,000
Other current assets	**336,000**	(1,138,000)
Accounts payable and accrued liabilities	**623,000**	(853,000)
Income taxes payable	**(199,000)**	71,000
NET CASH PROVIDED BY OPERATING ACTIVITIES	**9,349,000**	5,341,000
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to oil and gas properties	**(9,054,000)**	(5,064,000)
Proceeds from sale of oil and gas properties	**824,000**	118,000
Changes in other long-term assets	**(26,000)**	(198,000)
NET CASH USED IN INVESTING ACTIVITIES	**(8,256,000)**	(5,144,000)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from exercise of stock options (130,000 options in 2006 and 24,000 options in 2005)	**756,000**	185,000
Purchase of treasury stock (000 shares in 2006 and 500 shares in 2005)		8,000
NET CASH PROVIDED BY FINANCING ACTIVITIES	**756,000**	177,000
INCREASE IN CASH AND CASH EQUIVALENTS	**1,849,000**	374,000
CASH AND CASH EQUIVALENTS:		

Beginning of period		**1,935,000**		518,000
End of period	**$**	**3,784,000**	$	892,000
Supplemental cash flow information:				
Cash paid during the period for income taxes	**$**	**615,000**	$	
Cash paid during the period for interest	**$**		$	

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)
July 31, 2006

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, 2005.

The company effected a three-for-two stock split in the third fiscal quarter of 2005. All share and per share amounts discussed and disclosed in this Quarterly Report on Form 10-Q reflect the effect of that stock split.

Certain financial statement amounts have been reclassified to conform to the presentation used for the 2006 periods. Effective with the second quarter of 2006, the company has reclassified reimbursed overhead from operating revenue to general and administrative expense. For the nine months ended July 31, 2006 and 2005, the reclassified amounts were $548,000 and $487,000, respectively and for the three months ended July 31, 2006 and 2005, the reclassified amounts were $193,000 and $164,000 respectively.

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.

3. STOCK-BASED COMPENSATION

The company currently has one stock-based employee compensation plan, which 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, 2005. Prior to November 1, 2005, the company accounted for this plan under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, as permitted by Statement of Financial Accounting Standards (SFAS) No. 123, Accounting for Stock-Based Compensation. No stock-based employee compensation expense was recognized in the company s Consolidated Statement of Operations prior to November 1, 2005, as all options granted under the company s stock-based compensation plan had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective November 1, 2005, the company adopted the fair value recognition provisions of SFAS No. 123 (R), Share Based Payment, using the modified-retrospective-transition method. Under this transition method, the company restated the results of all prior periods back to the beginning of fiscal 1997 (the fiscal year of inception for this stock-based compensation plan) in accordance with the original provisions of SFAS No. 123. The cumulative effect of this restatement was an increase of $1,447,000 to capital in excess of par value and a decrease to retained earnings in the same amount. For the nine months ended July 31, 2006 and 2005, the company recognized compensation expense related to its stock option plan of $165,000 and $217,000, respectively and for the three months ended July 31, 2006 and 2005, the company recognized compensation expense of $46,000 and $69,000, respectively. The company has not made any option grants during fiscal 2006. The fair value of the 33,750 options granted during the nine months ended July 31, 2005 was estimated as of the grant date using the Black-Scholes option pricing model with the following assumptions: volatility, 48%; expected option term, 5 years; risk-free interest rate, 3.7% and; expected dividend yield, 0%. If option grants are made in the future, compensation expense for all such share-based payments granted, based upon the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R) will also be included in compensation expense.

Plan activity for the nine months ended July 31, 2006 is set forth below and has been adjusted for the 3-for-2 stock splits in fiscal 2005 and 2004 and the 20% stock dividend in 2003.

	Nine Months Ended July 31, 2006	
	Number of Options	Weighted Average Exercise Price
Outstanding at October 31, 2005	485,064	$ 5.78
Granted		
Exercised	(130,251)	5.80
Cancelled or forfeited	(26,249)	8.93
Outstanding at July 31, 2006	328,564	$ 5.53
Exercisable at July 31, 2006	279,939	$ 5.55
Weighted average contractual life at July 31, 2006		6.77

The following table summarizes information about stock options currently outstanding and exercisable at July 31, 2006:

	Outstanding			Exercisable	
Range of Exercise Prices	Number Outstanding at July 31, 2006	Weighted Average Remaining Contractual Life in Year	Weighted Average Exercise Price	Number Exercisable at July, 2006	Weighted Average Exercise Price
$3.09-$3.72	54,750	6.33	$3.56	44,625	$ 3.52
$5.93-$5.93	273,814	6.87	$5.93	235,314	$ 5.93
$3.09-$5.93	328,564	6.77	$5.53	279,939	$ 5.55

Total estimated unrecognized compensation cost from unvested stock options as of July 31, 2006 was approximately $137,000, which is expected to be recognized over an average period of approximately 0.83 years.

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, 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 Panhandle Eastern Pipeline Company for Texas, Oklahoma (mainline) (PEPL) which serves the regions where the company produces the majority of its gas. Such hedges, which are accounted for as cash flow hedges, do not exceed estimated production volumes, where applicable, 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.

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The company recognizes all derivatives (consisting solely of cash flow hedges) on the 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 (Loss) on the Consolidated Balance Sheets and then are reclassified 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 after tax hedging losses of $190,000 in the first nine months of 2006 and after tax hedging losses of $207,000 for the same period in 2005. Any hedge ineffectiveness, which was not material for the first nine months of 2006 and 2005, is immediately recognized in gas sales. The company had no open hedge positions at July 31, 2006.

Subsequent to third quarter end 2006, the company entered into hedge transactions totaling 80,000 MMbtu for the quarter ending January 31, 2007, 230,000 MMbtu for the quarter ending April 30, 2007 and 240,000 MMbtu for the quarter ending July 31, 2007. These hedges are intended to cover between 20% and 50% of the company s current production base without taking into consideration production additions during the interim periods. The hedges are indexed to PEPL with a weighted average contract price of $9.59 for the quarter ending January 31, 2006, $8.25 for the quarter ending April 30, 2007 and $6.85 for the quarter ending July 31, 2007. Individual month basis differentials to the NYMEX and Henry Hub range from minus $.90 to minus $1.46.

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 $2,000,000 with interest calculated at the prime rate. The facility is unsecured and has affirmative covenants which 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 unfunded debt in excess of $500,000. The hedging line of credit expires on October 31, 2006.

5. COMPREHENSIVE INCOME

Comprehensive income includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. The components of comprehensive income for the three and nine months ended July 31, 2006 and 2005 are as follows:

	Nine Months Ended July 31,		Three Months Ended July 31,	
	2006	2005	**2006**	2005
Net income	**$ 4,373,000**	$ 3,345,000	**$ 1,286,000**	$ 1,362,000
Other comprehensive income:				
Change in fair value of derivatives	**425,000**	567,000		7,000
Income tax expense	**(119,000)**	(166,000)		(2,000)
Total comprehensive income	**$ 4,679,000**	$ 3,746,000	**$ 1,286,000**	$ 1,367,000

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6. EARNINGS PER SHARE

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

	Nine Months Ended July 31,					
	2006			2005		
	Net Income	**Shares**	**Net Income Per Share**	Net Income	Shares	Net Income Per Share
Basic earnings per share	**$ 4,373,000**	**9,191,000**	**$ .48**	$ 3,345,000	9,069,000	$ .37
Effect of dilutive shares of common stock from stock options		**321,000**	**(.02)**		262,000	(.01)
Diluted earnings per share	**$ 4,373,000**	**9,512,000**	**$ .46**	$ 3,345,000	9,331,000	$ .36

	Three Months Ended July 31,					
	2006			2005		
	Net Income	**Shares**	**Net Income Per Share**	Net Income	Shares	Net Income Per Share
Basic earnings per share	**$ 1,286,000**	**9,231,000**	**$ .14**	$ 1,362,000	9,087,000	$ .15
Effect of dilutive shares of common stock from stock options		**267,000**	**(.00)**		252,000	(.00)
Diluted earnings per share	**$ 1,286,000**	**9,498,000**	**$ .14**	$ 1,362,000	9,339,000	$ .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.

8. COMPRESSOR AND TUBULAR INVENTORY

Compressor and tubular inventory are finished goods, recorded at cost, which are expected to be used in the future development of certain of the company s oil and gas properties. The company has classified this amount as a long-term asset because the compressors and tubulars are not held for re-sale and the cost, net of amounts billed to joint interest owners in the normal course of business, will eventually be included in evaluated properties.

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9. UNEVALUATED OIL AND GAS PROPERTIES

Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until they are evaluated. The following table shows, by category of cost and date incurred, the unevaluated oil and gas property costs excluded from the amortization computation as of July 31, 2006:

Net Costs Incurred During Periods Ended:	Exploration Costs	Development Costs	Acquisition Costs	Total Unevaluated Properties
July 31, 2006	$ 875,000	$ 118,000	$ 1,757,000	$ 2,750,000
October 31, 2005	110,000	133,000	1,946,000	2,189,000
October 31, 2004			329,000	329,000
	$ 985,000	$ 251,000	$ 4,032,000	$ 5,268,000

10. COMMITMENTS

The company had no material outstanding commitments at July 31, 2006.

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.

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LIQUIDITY AND CAPITAL RESOURCES

At July 31, 2006, working capital was $8,920,000, compared to $7,697,000 at July 31, 2005. For the nine months ended July 31, 2006, net cash provided by operating activities increased $4,008,000, or 75%, to $9,349,000 when compared to net cash provided by operating activities of $5,341,000 for the same period in 2005. This increase is primarily the result of increases in net income and other non-cash items of $1,920,000; a net increase of $363,000 in short term investments in 2006 versus a net decrease in short term investments of $859,000 in 2005 which resulted in a net decrease in cash provided by operating activities of $1,222,000 between the two periods; a net increase in cash provided by operating activities as a result of changes in accrued oil and gas sales, trade receivables and other current assets of $2,105,000; and a net increase in cash provided by operating activities as a result of changes in accounts payable and income taxes payable of $1,347,000. For the nine months ended July 31, 2006 and 2005, net cash used in investing activities was $8,256,000 and $5,144,000, respectively. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $9,054,000 and $5,064,000, respectively.

The average return on the company s investments for the nine months ended July 31, 2006 and 2005 was 6.0% and 3.1%, respectively. At July 31, 2006, approximately 55% of the investments were directly invested in mutual funds and were managed by professional money managers. Remaining investments are in managed partnerships 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 July 31, 2006, 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 $8,711,000 for the nine months ended July 31, 2006 from $6,284,000 for the nine months ended July 31, 2005. 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:

	Nine Months Ended July 31,	
	2006	2005
RECONCILIATION OF EBITDA:		
Net Income	**$ 4,373,000**	$ 3,345,000
Add Back:		
Interest Expense	**27,000**	28,000
Income Tax Expense	**1,743,000**	1,301,000
Depreciation, Depletion and Amortization Expense	**2,568,000**	1,610,000
EBITDA	**$ 8,711,000**	$ 6,284,000

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OFF-BALANCE SHEET FINANCING

The company has no off-balance sheet financing arrangements at July 31, 2006.

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 Panhandle Eastern Pipeline Company for Texas, Oklahoma (mainline) (PEPL) which serves the regions where the company produces the majority of its gas. Refer to Note 4 of the Consolidated Financial Statements for a complete discussion on the company s hedging activities.

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.

	Nine Months Ended July 31,					
	2006		2005		% Change	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**1,528,000**	**$ 6.46**(1)	1,311,000	$ 5.70(2)	+ 16%	+ 13%
Oil (bbls)	**31,400**	**$61.74**	27,700	$47.37	+ 13%	+ 30%

	Three Months Ended July 31,					
	2006		2005		% Change	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**563,000**	**$ 5.70**	469,000	$ 6.25(3)	+ 20%	- 9%
Oil (bbls)	**11,600**	**$65.80**	8,200	$56.21	+ 41%	+ 17%

(1) Includes $0.18 Mcf hedging loss.

(2) Includes $0.22 Mcf hedging loss.

(3) Includes $0.02 Mcf hedging loss.

OPERATIONS

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

As discussed below, the company recently expanded into South Texas through an exploration program using 3-D seismic to define the Vicksburg, Frio, Queen City and Wilcox prospects in Hidalgo and Jim Hogg counties and into north-central Kansas through an exploration program using 3-D seismic to define Lansing-Kansas City oil prospects in Graham and Sheridan counties.

Also as discussed below, the company recently expanded its Calliope operations into Texas and Louisiana. The company believes these are fertile areas for Calliope and will continue to expand as opportunities allow.

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 and volume of Calliope installations available to the company.

The company will continue to actively pursue adding reserves through its two core projects in fiscal 2006 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 of oil field services such as drilling rigs, production equipment and related services, and access to wells for application of the company s patented liquid lift 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 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.

Drilling Activities.

Northern Anadarko Shelf The company currently drills primarily on its 60,000 gross acre inventory located along the northern shelf of the Anadarko Basin where it has drilled about 70 wells. The wells targeted the Morrow, Oswego and Chester formations between 7,000 and 10,000 feet. A substantial number of additional wells are anticipated for the area.

Drilling is not restricted to the northern Anadarko shelf acreage. The company is generating prospects elsewhere in the Anadarko Basin, the Oklahoma Panhandle, north-central Oklahoma, north-central Kansas and South Texas. For the nine months ended July 31, 2006, the company drilled 11 wells on its northern Anadarko Shelf acreage.

During fiscal 2006, 4 wells have been drilled on the company s 5,760 gross acre Glacier Prospect. The most important of these wells are the Garnet State and Scarlet State drilled on the north portion of the prospect. Both wells encountered excellent Morrow sands at about 7,500 feet, and are producing at high rates for the area. Combined production for the wells has exceeded 1.1 Bcf since they were placed on production in February and June 2006, respectively. The wells are currently producing at a combined daily rate of approximately 7.4 MMcf. Previously, the company drilled two other high rate wells on the Glacier prospect, both of which had limited reservoir extent but proved the presence of high quality sands on the prospect. A number of additional wells are expected to be drilled on the prospect with two to three more wells scheduled during calendar 2006. The company owns a 57% working interest in the Garnet State and a 55% interest in the Scarlet State, and is the operator of both wells and the prospect.

Drilling is also continuing on the company s 2,560 gross acre Buffalo Creek Prospect. In February 2006 the company completed the 6,900-foot Lauer #1-21 well as the third producing oil well on the prospect. In anticipation of additional drilling, a 3-D seismic program is currently underway on the Buffalo Creek Prospect to identify additional drilling locations. The company owns a 31% working interest.

A second well has recently been drilled on the company s 1,280 gross acre Saddle Prospect which appears to be productive and is awaiting pipeline connection. The company owns a 49% working interest and is the operator. Additional wells are scheduled for the prospect.

Drilling Program Expansion and Diversification During fiscal 2005, the company significantly expanded both the volume and breadth of its exploration program with new projects in South Texas and north-central Kansas. It is the company s intention to diversify its exploration geographically, scientifically, and in terms of capital, risk and reserve potential. Compared to drilling in Oklahoma, the South Texas project involves higher costs and greater risks but significantly higher per well reserve potential. The north-central Kansas project is geared to oil exploration and has excellent potential to add significant reserves at moderate costs and risks. Both projects are in areas where 3-D seismic is a proven exploration tool and where continuing refinements are providing excellent exploration success. Equally as important, both exploration teams specialize in their respective geographic areas and have been highly successful finding new reserves using 3-D seismic.

South Texas During 2005, the company commenced a new exploration project in South Texas. The project has far greater per well production and reserve potential than the company s core drilling projects, and provides the opportunity to materially increase the company s reserves. However, it also carries a much higher cost and greater risk. In return for a 37.5% interest, the company committed $1,500,000 for prospect generation and leasing costs. The company has the option to participate in each prospect for all, or a portion, of its interest. If the company does not participate for the full interest, the remaining amount will be sold to industry participants on a promoted basis.

The project is 3-D seismic driven and focuses on the Vicksburg, Frio and Queen City sands in Hidalgo and Jim Hogg Counties ranging in depth from 7,500 to 15,000 feet. Both the cost and the potential of this project far exceed anything the company has done before. Leasing is complete on four prospects. The first well drilled in the project was the 10,500-foot Peery #1 located on the Robertson Prospect in Hidalgo County. The well targeted the Frio sands. Multiple up-hole sands are currently being tested for commercial production. The company owns a 37.5% interest in the well. The 8/8ths cost of the well is expected to range between $3,500,000 and $4,000,000.

The next South Texas well scheduled for drilling is the 12,500-foot Rosa Amarilla well on the Esparza Prospect. The Rosa Amarilla well is a step-out from excellent production. The company currently owns a 37.5% working interest. The estimated cost of field services has almost doubled since the prospect was originated with the completed well cost now estimated between $6,000,000 and $7,000,000. Although the well has very high reserve potential, the company is presently considering significantly reducing its interest in the well to mitigate its risk exposure to high drilling costs and the availability of quality field services.

The remaining two leased prospects consist of development drilling on the Santa Ana Prospect and a wildcat test on the West Mestena Prospect. The company currently owns a 37.5% working interest in both prospects. The prospects will be drilled as rigs become available. The company is considering the amount of interest to retain in the prospects in view of rapidly escalating drilling costs and the availability of quality field services.

North-Central Kansas During 2005, the company took another significant step to diversify its exploration by acquiring a 30% interest in 20,000 gross acres along the Central Kansas Uplift. Drilling targets the Lansing-Kansas City formation at 4,000 feet. This project is expected to be an excellent supplement to the company s Oklahoma drilling. Together, the Oklahoma and Kansas drilling programs are expected to replace the company s production in each of the next three to five years, and to provide moderate growth in both production and reserves.

The company s acreage is located in a prolific producing area where 3-D seismic has recently proven to be an effective exploration tool. Higher oil prices have justified using 3-D seismic technology to locate undrilled structures that are very difficult to find with old technology.

The Kansas project provides diversification to the company s drilling program, both geographically and scientifically, through the use of 3-D seismic. It also exclusively targets oil reserves which will help bring better product balance to the company s reserve base.

In north-central Kansas, approximately 28 square miles of 3-D seismic have been shot and evaluated. At least five exploratory wells will be drilled. Completed costs for individual wells are estimated to be approximately $300,000.

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The first two wells confirmed the seismic interpretation and encountered multiple sands. However, the sands were either tight or wet, resulting in dry holes. As with its other drilling projects, the company expects successful results to occur unevenly over time. Drilling is expected on approximately 30 prospects.

Calliope Drilling Project See discussion under Calliope Gas Recovery Technology below.

Calliope Gas Recovery Technology.

The company owns the exclusive right to a patented technology known as the Calliope Gas Recovery System. Calliope can achieve substantially lower flowing bottom hole pressure than conventional production methods because it does not rely on reservoir pressure to lift liquids. 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 has recently begun implementing strategies designed to expand the population of wells on which Calliope should be installed.

Realizing Calliope s value continues to be a top priority of the company. The company is 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 systems are currently installed on 18 wells that are owned and operated by CREDO. These wells range in depth from 6,500 to 18,400 feet. They represent the most rigorous applications for Calliope because the wells were either totally dead or uneconomic at the time Calliope was installed. Initial production rates range up to 650 Mcfd (thousand cubic feet of gas per day) and average per well Calliope reserves for non-prototype wells are estimated to be 1.10 Bcf. One of the company s early Calliope installations, the J.C. Carroll well, has now produced almost a billion cubic feet of gas.

During 2005, the company successfully expanded its Calliope operations into Texas with two installations in southwest Texas and one in Louisiana. The company considers Texas and Louisiana to be very fertile areas for Calliope and has retained personnel and opened an office in the region to focus exclusively on Calliope.

In southwest Texas, the company successfully installed two 11,000-foot prototype Calliope installations which once again broadened Calliope s down-hole application, successfully lifting several times more fluid volume than Calliope has previously lifted from the company s Oklahoma wells. Calliope immediately returned the wells to economic production making up to 210 Mcfd. In central Louisiana, the company recently installed Calliope on a 13,800-foot well. Calliope immediately restored the well to economic production making 320 Mcfd. Each of these Calliope installations have created wells that are once again highly economic.

The company currently has two Calliope candidate wells that are awaiting Calliope installations, both located in Oklahoma. If the company experiences no significant procurement delays, it expects that the installations will be completed in 2006.

Joint Ventures With Third Parties In an effort to increase the number of Calliope installations, the company is seeking 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 a keen interest in Calliope and joint venture discussions are continuing with a number of the companies, including evaluation of candidate wells.

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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 believes that it will achieve a breakthrough in the joint venture area.

Calliope Drilling Project The company has entered into a joint venture with Redman Energy Holdings II, L.P. to drill wells for the purpose of using its patented Calliope Gas Recovery System to develop stranded gas reserves. Redman Energy Holdings is an affiliate of Redman Energy Corporation, a privately-held, Houston-based E&P company. Redman is affiliated with Natural Gas Partners, a highly respected industry funding source, and brings a wealth of knowledge and a solid operating foundation in the project area. Drilling will concentrate on previously mature, prolific fields containing significant stranded gas.

In its initial phases, the joint venture plans to invest up to $35,000,000 to acquire leases, drill new wells, and install Calliope principally in South and East Texas. Drilling will target large gas fields that were abandoned when natural gas prices were considerably lower than today, and when fluid lift technologies were much less effective than Calliope. The company presently expects to fund its 50% share of the joint venture from existing cash and future cash flow.

Access to fields and drilling locations are generally available through leasing. The company believes this project is a target-rich opportunity for the company to expand its Calliope operations. Wells are expected to range in depth from 8,000 to 12,000 feet. Reserves are projected to range from 1.0 to 3.0 Bcfe (billion cubic feet of gas equivalent) per well, with beginning production rates ranging from 500 to 1,000 Mcf per day. Average drilling economics are expected to include payouts of less than two years and internal rates of return from 50% to 100%.

The company believes that the ability to configure larger casing and tubular sizes in newly drilled wells will maximize Calliope s potential. This is expected to substantially improve reserve recoveries and production rates compared to installing Calliope on existing wells.

In this Quarterly Report on Form 10-Q, the company is providing the following information to enhance and supplement the disclosures regarding Reserve Replacement Percentage and Finding Cost per Mcfe which are contained in its Annual Report on Form 10-K for the year ended October 31, 2005. The company will eliminate disclosure of Reserve Replacement Percentage and Finding Cost per Mcfe from its 1933 and 1934 Act filings, beginning with its Annual Report on Form 10-K for the fiscal year ending October 31, 2006, because the information is generally available from independent sources.

The company previously disclosed in its most recent Annual Report on Form 10-K that, during the fiscal year ended October 31, 2005 the company replaced 106% of the reserves produced in fiscal 2005. This reserve replacement percentage is derived directly from the line items disclosed in the reconciliation of beginning and ending proved reserve quantities contained in Footnote 8 to the Consolidated Financial Statements, Supplementary Oil and Gas Information, page 42 of the company s Annual Report on Form 10-K. The table

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below shows the calculation used by the company at October 31, 2005. Oil is converted to gas for the calculation of Mcfe (thousand cubic feet equivalent) on the basis of one barrel of oil is equal to six Mcf of gas.

	Year Ended October 31, 2005		
	Gas (Mcf)	Oil (Bbls)	Total (Mcfe)
Extensions and discoveries	2,962,000	22,000	3,094,000
Revisions of previous estimates	(889,000)	(6,000)	(925,000)
Total proved reserve additions	2,073,000	16,000	2,169,000
Production	1,830,000	37,000	2,052,000
Reserve replacement percentage			106%

The company previously disclosed in its Annual Report on Form 10-K for the fiscal year ended October 31, 2005 that its finding cost for the period was $2.73 per Mcfe excluding start-up costs in South Texas and north-central Kansas. The company believes that excluding these start-up costs provides a meaningful matching of current costs with current reserve additions. Finding costs are derived from the line item Total Including Asset Retirement Obligation disclosed in the table identifying Acquisition, Exploration and Development Costs Incurred contained in Footnote 8 to the Consolidated Financial Statements, Supplementary Oil and Gas Information, page 41 of the company s Annual Report on Form 10-K and from the line items disclosed in the reconciliation of beginning and ending proved reserve quantities contained in Footnote 8 to the Consolidated Financial Statements, Supplementary Oil and Gas Information, page 42 of the company s Annual Report on Form 10-K. The table below shows the calculation used by the company at October 31, 2005.

	October 31, 2005
Total Acquisition, Exploration and Development Costs Incurred Including Asset Retirement Obligation	$ 7,327,000
Less South Texas and north-central Kansas start-up costs	(1,401,000)
Net Acquisition, Exploration and Development Costs Incurred Including Asset Retirement Obligation	$ 5,926,000
Total Proved Reserve (Mcfe) Additions (see table above)	2,169,000
Finding Cost Per Mcfe	$ 2.73

Proved reserve additions, including the proved developed and proved undeveloped portions can be calculated from the information in Footnote 8 to the Consolidated Financial Statements, Supplementary Oil and Gas Information, page 42 of the company s Annual Report on Form 10-K. As is stated in Management s Discussion and Analysis of Financial Condition and Results of Operations, Oil and Gas Activities, Drilling Activities, and Calliope Gas Recovery System on pages 19 through 22 of the company s Annual Report on Form 10-K, these proved reserve additions for the fiscal year ended October 31, 2005 were primarily the result of activity on the company s two core projects, drilling along the shelf of the Northern Anadarko Basin in northwest Oklahoma and application of the company s patented liquid lift system on low pressure gas wells.

The company uses only proved reserves to calculate the reserve replacement percentage and finding costs described above and does not include any proved reserves attributable to consolidated entities or investments accounted for using the equity method.

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The finding costs and production replacement measures are used by the company as one way of measuring the company s performance and comparing it to that of its competitors and the industry. The calculation of both of these performance measures is based, in part, on estimated proved oil and gas reserve quantities. As is more fully described under Item 2., Properties, Significant Properties, Estimated Proved Oil and Gas reserves, and Future Net Revenues on pages 11 and 12 of the company s Annual Report on Form 10-K for the fiscal year ended October 31, 2005, estimates of reserve quantities must be viewed as being subject to significant change as more data about the company s properties becomes available. Additionally, both of these performance measures are historical in nature and are calculated as of a specific date, and may not be indicative of the company s future performance.

The company s success depends primarily on locating and producing new reserves, the level of production from existing wells, and prices of oil and natural gas. Production from the company s oil and gas properties declines over time. In order to maintain current production rates the company must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. In addition, competition for oil and gas leases, oil field services, and producing oil and gas properties is intense and many of the company s competitors have financial and other resources substantially greater than those available to it. Without success on its core projects, the company s reserves, production and revenues will decline rapidly.

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.

Results of Operations

Nine Months Ended July 31, 2006 Compared to Nine Months Ended July 31, 2005

For the nine months ended July 31, 2006, total revenues increased 36% to $12,255,000 compared to $8,986,000 last year. As the oil and gas price/volume table on page 13 shows, total gas price realizations, which reflect hedging transactions, increased 13% to $6.46 per Mcf and oil price realizations increased 30% to $61.74 per barrel. The net effect of these price changes was to increase oil and gas sales by $1,400,000. For the nine months ended July 31, 2006, the company s gas equivalent production increased 16%. The effect of the volume change was to increase oil and gas sales by $1,624,000. Investment income and other increased $245,000 primarily due to improved performance of the company s investments.

For the nine months ended July 31, 2006, total costs and expenses rose 41% to $6,139,000 compared to $4,340,000 for the comparable period in 2005. Oil and gas production expenses increased 36% due primarily to an increase in production taxes and lease operating expense. Production taxes increased during the current period primarily due to increased production revenue and the company s receipt of a production tax rebate during the 2005 period. The increase in lease operating expense is primarily due to an increase in the number of wells owned by the company and from additional workover expenses incurred during the 2006 period. Depreciation, depletion and amortization (DD&A) increased primarily due to increased production and an increase in the amortizable cost base. General and administrative expenses increased primarily due to costs associated with compliance with Sarbanes-Oxley regulations. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 28.5% for the 2006 period and 28.0% for the 2005 period.

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Three Months Ended July 31, 2006 Compared to Three Months Ended July 31, 2005

For the three months ended July 31, 2006, total revenues increased 13% to $3,969,000 compared to $3,501,000 during the same period last year. As the oil and gas price/volume table on page 13 shows, total gas price realizations, which reflect hedging transactions, decreased 9% to $5.70 per Mcf and oil price realizations increased 17% to $65.80 per barrel. The net effect of these price changes was to decrease oil and gas sales by $183,000. For the three months ended July 31, 2006, the company s gas equivalent production increased 22% resulting in an oil and gas sales increase of $752,000. Investment and other income declined $102,000 primarily due to poorer performance of the company s investments, compared to last year.

For the three months ended July 31, 2006, total costs and expenses rose 35% to $2,170,000 compared to $1,609,000 for the comparable period in 2005. Oil and gas production expenses increased due primarily to an increase in production taxes and lease operating expense. DD&A rose primarily due to increased production and an increase in the amortizable cost base. General and administrative expenses increased primarily due to costs associated with compliance with Sarbanes-Oxley regulations. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 28.5% for the 2006 period and 28.0% for the 2005 period.

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.

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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.

At October 31, 2005, the date of the company s most recent reserve report, the company s reserves, and reserve values, were concentrated in 54 properties (Significant Properties). Some of the Significant Properties were individual wells and others were multi-well properties. The Significant Properties represented 28% of the company s total properties but a disproportionate 76% of the discounted value (at 10%) of the company s reserves. Individual wells on which the company s patented liquid lift system is installed comprise 22% of the Significant Properties and represented 32% of the discounted reserve value of such properties. Relatively new wells comprised 22% of the Significant Properties and represented 24% of the discounted value of such properties.

Estimates of reserve quantities and values for certain Significant Properties must be viewed as being subject to significant change as more data about the properties becomes available. Such properties include wells with limited production histories and properties with proved undeveloped or proved non-producing reserves. In addition, the company s patented liquid lift system is generally installed on mature wells. As such, they contain older down-hole equipment that is more subject to failure than new equipment. The failure of such equipment, particularly casing, can result in complete loss of a well. Historically, performance of the company s wells has not caused significant revisions in its proved reserves.

The following table sets forth, as of October 31 of the indicated year, information regarding the company s proved reserves which is based on the assumptions set forth in Note (8) to the company s Consolidated Financial Statements on Form 10-K for the year ended October 31, 2005 where additional reserve information is provided. The average price used to calculate estimated future net revenues was $55.59, $50.43 and $28.64 per barrel of oil and $10.26, $5.84, and $3.99 per Mcf of gas as of October 31, 2005, 2004, and 2003, respectively. Amounts do not include estimates of future Federal and state income taxes.

Year	Oil (bbls)*	Gas (Mcf)*	Estimated Future Net Revenues	Estimated Future Net Revenues Discounted at 10%
2005	386,000	15,516,000	$ 136,878,000	$ 81,209,000
2004	407,000	15,273,000	$ 77,612,000	$ 44,551,000
2003	385,000	13,786,000	$ 45,165,000	$ 28,024,000

* The percentage of total reserves classified as proved developed was approximately 89% in 2005, 93% in 2004 and 99% in 2003.

Estimated Future Net Revenues Discounted at 10% is not a GAAP measure of operating performance. Because the company drills new wells on an ongoing basis, and plans to continue to do so in the future, it expects to continue to generate deferred income taxes which are not reasonably expected to be paid in the near term. This pre-tax, non-GAAP measure is used by the company in connection with estimating funds expected to be available in the future for drilling and other operating activities. The company believes that this performance measure may also be useful to investors for the same purpose. The difference between this measure and the Standardized Measure of Discounted Future Net Cash Flows From Reserves is that this measure excludes future income tax expense and the effect of the 10% discount factor on future income tax expense. In this Form 10-Q, the company is providing the following information to enhance and supplement the disclosures contained in it Form 10-K for the year ended October 31, 2005. The following table provides a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows From Reserves as shown in Note 8 to the company s Consolidated Financial Statements on Form 10-K for the year ended October 31, 2005.

	Year Ended October 31,		
	2005	2004	2003
Estimated future net revenues discounted at 10%	$ 81,209,000	$ 44,551,000	$ 28,024,000
Future income tax expense	(36,054,000)	(19,965,000)	(11,094,000)
Effect of the 10% discount factor on future income tax expense	14,332,000	8,273,000	4,211,000
Standardized measure of discounted future net cash flows from reserves	$ 59,487,000	$ 32,859,000	$ 21,141,000

Price changes will affect the economic lives of oil and gas properties and, therefore, price changes may cause reserve revisions. Price changes have not caused significant proved reserve revisions by the company except in 1986 when a 51% decline in oil prices and a 45% decline in natural gas prices resulted in an 8.7% reduction in estimated proved reserves. Based upon this historical experience, the company does not believe its reserve estimates are particularly sensitive to prices changes within historical ranges.

One measure of the life of the company s proved reserves can be calculated by dividing proved reserves at a fiscal year end by production for that fiscal year. This measure yields an average reserve life of nine years at October 31, 2005. Since this measure is an average, by definition, some of the company s properties will have a life shorter than the average and some will have a life longer than the average. The expected economic lives of the company s properties may vary widely depending on, among other things, the size and quality, natural gas and oil prices, possible curtailments in consumption by purchasers, and changes in governmental regulations or taxation. As a result, the company s actual future net cash flows from proved reserves could be materially different from its estimates.

The company is not aware of any material adverse issues related to its reserves regarding regulatory approval, the availability of additional development capital, or the installation of additional infrastructure.

ASSET RETIREMENT OBLIGATIONS. SFAS No. 143, *Accounting for Asset Retirement Obligations* requires that the company estimate the future cost of asset retirement obligations, discount that cost to its present value, and record 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.

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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

The effectiveness of our or any system of disclosure controls and procedures is subject to certain limitations, including the exercise of judgment in designing, implementing and evaluating the controls and procedures, the assumptions used in identifying the likelihood of future events, and the inability to eliminate misconduct completely. As a result, there can be no assurance that our disclosure controls and procedures will detect all errors or fraud. By their nature, our, or any, system of disclosure controls and procedures can provide only reasonable assurance regarding management s control objectives.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we evaluated the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act) as of July 31, 2006. On the basis of this review, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures are designed, and are effective, to give reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and to ensure that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, in a manner that allows timely decisions regarding required disclosure. There were no changes in the company s internal controls over financial reporting that occurred in the third fiscal quarter of 2006 that materially affected or were reasonably likely to materially affect, its internal control over financial reporting.

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, 2005.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

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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)

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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.

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: September 14, 2006

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Exhibit Index

Exhibit Numbers	Description
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