CREDO PETROLEUM CORP
Form 10-Q
September 10, 2012
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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 July 31, 2012

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)

Delaware	**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 has submitted electronically and posted on its corporate web site, if any, every interactive data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files.) Yes x No o

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

Large accelerated filer o	Accelerated filer x
Non-accelerated filer o (Do not check if a smaller reporting company)	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**
September 10, 2012	Common stock, $.10 par value	10,041,000

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CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

Quarterly Report on Form 10-Q For the Period Ended July 31, 2012

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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

A S S E T S

	July 31, 2012 (Unaudited)	October 31, 2011
Current Assets:		
Cash and cash equivalents	**$ 2,260,000**	$ 3,313,000
Short-term investments	**394,000**	1,487,000
Receivables:		
Accrued oil and gas sales	**3,818,000**	2,343,000
Trade	**4,911,000**	1,707,000
Derivative assets	**40,000**	8,000
Other current assets	**617,000**	213,000
Total current assets	**12,040,000**	9,071,000
Long-term Assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	**11,512,000**	9,957,000
Evaluated oil and gas properties	**129,274,000**	100,948,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	**(66,881,000)**	(61,054,000)
Net oil and gas properties, at cost, using full cost method	**73,905,000**	49,851,000
Intangible assets, net of accumulated amortization of $1,634,000 in 2012 and $1,307,000 in 2011	**2,815,000**	3,142,000
Compressor and tubular inventory to be used in development	**1,258,000**	1,760,000
Other, net	**28,000**	97,000
Total Assets	**$ 90,046,000**	$ 63,921,000

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

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LIABILITIES AND STOCKHOLDERS EQUITY

	July 31, 2012 (Unaudited)	October 31, 2011
Current Liabilities:		
Accounts payable and accrued liabilities	**$ 22,025,000**	$ 6,933,000
Revenue distribution payable	**981,000**	964,000
Accrued compensation	**404,000**	246,000
Income taxes payable	**105,000**	105,000
Total current liabilities	**23,515,000**	8,248,000
Long Term Liabilities:		
Long-term debt	**6,000,000**	
Deferred income taxes, net	**6,149,000**	4,524,000
Asset retirement obligation	**1,444,000**	1,213,000
Total liabilities	**37,108,000**	13,985,000
Commitments:		
Stockholders Equity:		
Preferred stock, no par value, 5,000,000 shares authorized, none issued		
Common stock, $.10 par value, 20,000,000 shares authorized, 10,660,000 issued	**1,066,000**	1,066,000
Capital in excess of par value	**31,531,000**	31,547,000
Treasury stock at cost, 619,000 shares in 2012 and 2011	**(4,654,000)**	(4,654,000)
Retained earnings	**24,995,000**	21,977,000
Total stockholders equity	**52,938,000**	49,936,000
Total Liabilities and Stockholders Equity	**$ 90,046,000**	$ 63,921,000

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, 2012	Nine Months Ended July 31, 2011	Three Months Ended July 31, 2012	Three Months Ended July 31, 2011
Oil sales	**$ 15,952,000**	$ 8,678,000	**$ 5,691,000**	$ 3,358,000
Natural gas sales	**2,091,000**	3,128,000	**671,000**	1,130,000
	18,043,000	11,806,000	**6,362,000**	4,488,000
Costs and expenses:				
Oil and natural gas production	**3,521,000**	2,893,000	**1,294,000**	1,059,000
Depreciation, depletion and amortization	**6,181,000**	3,401,000	**2,343,000**	1,260,000
General and administrative	**3,534,000**	2,016,000	**1,849,000**	820,000
	13,236,000	8,310,000	**5,486,000**	3,139,000
Income from operations	**4,807,000**	3,496,000	**876,000**	1,349,000
Other income and (expense)				
Realized and unrealized gain (loss) from derivative contracts	**(167,000)**	(671,000)	**716,000**	984,000
Investment and other income	**3,000**	55,000		(4,000)
	(164,000)	(616,000)	**716,000**	980,000
Income before income taxes	**4,643,000**	2,880,000	**1,592,000**	2,329,000
Income taxes	**(1,625,000)**	(749,000)	**(664,000)**	(622,000)
Net income	**$ 3,018,000**	$ 2,131,000	**$ 928,000**	$ 1,707,000
Earnings per share of Common Stock Basic	**$ .30**	$ .21	**$ .09**	$ .17
Earnings per share of Common Stock Diluted	**$ .30**	$ .21	**$ .09**	$ .17
Weighted average number of shares of Common Stock and dilutive securities:				
Basic	**10,041,000**	10,042,000	**10,041,000**	10,041,000
Diluted	**10,088,000**	10,078,000	**10,096,000**	10,072,000

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, 2012	Nine Months Ended July 31, 2011
Cash Flows From Operating Activities:		
Net income	**$ 3,018,000**	$ 2,131,000
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**6,181,000**	3,401,000
ARO liability accretion	**54,000**	78,000
Unrealized (gain) loss on derivative instruments	**(32,000)**	497,000
Deferred income taxes	**1,625,000**	661,000
Gain on short term investments		(47,000)
Compensation expense related to stock options granted	**15,000**	47,000
Changes in operating assets and liabilities:		
Purchase of short term investments		(50,000)
Proceeds from short-term investments	**1,093,000**	102,000
Accrued oil and gas sales	**(1,475,000)**	(1,102,000)
Trade receivables	**(3,204,000)**	96,000
Other current assets	**(404,000)**	(3,000)
Accounts payable and accrued liabilities	**903,000**	2,243,000
Net Cash Provided By Operating Activities	**7,774,000**	8,054,000
Cash Flows From Investing Activities:		
Additions to oil and gas properties	**(15,745,000)**	(11,468,000)
Proceeds from sale of oil and gas properties	**405,000**	
Changes in other long-term assets	**544,000**	(5,000)
Net Cash Used In Investing Activities	**(14,796,000)**	(11,473,000)
Cash Flows From Financing Activities:		
Purchase of treasury stock		(145,000)
Payment in lieu of stock option exercise	**(31,000)**	
Proceeds from line of credit	**6,000,000**	
Net Cash Provided By (Used) In Financing Activities	**5,969,000**	(145,000)
Decrease In Cash And Cash Equivalents	**(1,053,000)**	(3,564,000)
Cash And Cash Equivalents:		
Beginning of period	**3,313,000**	7,179,000
End of period	**$ 2,260,000**	$ 3,615,000

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)

July 31, 2012

1. BASIS OF PRESENTATION

On June 3, 2012, the Company signed a merger agreement with Forestar Group Inc. (Forestar) pursuant to which Forestar will pay $14.50 for each share of the Company s stock, or approximately $146 million in cash. Consummation of the merger is not subject to a financing condition, but is subject to customary closing conditions, including the approval of Credo s stockholders. A special meeting of the Company s stockholders is scheduled to be held on September 25, 2012, at which stockholders will vote whether or not to approve the merger. The merger has been approved by the boards of directors of the Company and Forestar. Assuming the satisfaction of conditions, the merger could close prior to the Company s fiscal year-end. As the transaction remains subject to certain closing conditions, there can be no assurance that this merger will be consummated, therefore, these consolidated financial statements and footnotes have been prepared under the assumption that the Company will continue under the current ownership structure. Additional information regarding the merger can be found in our Form 8-K filed on June 4, 2012 and our Definitive Proxy Statement filed on August 10, 2012.

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. For a more complete understanding of the Company s financial condition and accounting policies, these consolidated financial statements should be read in conjunction with the Company s Annual Report on Form 10-K/A for the fiscal year ended October 31, 2011. The results for interim periods are not necessarily indicative of annual results.

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.

2. OIL AND NATURAL GAS PROPERTIES

Depreciation, depletion and amortization of oil and natural gas properties for the nine months ended July 31, 2012 and 2011 were $5,827,000 and $3,042,000, respectively, and were $2,225,000 and $1,141,000 for the three months ended July 31, 2012 and 2011, respectively. The increase is primarily related to property cost additions for future development costs of proved undeveloped Bakken and Three Forks reserve additions made starting in the fourth quarter of fiscal 2011. The Company uses the full cost method of accounting for costs related to its oil and natural gas properties. Amortizable capitalized costs included in the full cost pool are depleted on an aggregate basis using the units-of-production method. All costs incurred in the acquisition, exploration, and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes, and overhead related to exploration and development activities) and the fair value of estimated future costs of site restoration, dismantlement, and abandonment activities are capitalized. Costs for unevaluated properties, which typically include lease rentals, geology and seismic costs, are capitalized but are excluded from the amortizable pool during the evaluation period. When determinations are made whether the property has

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proved recoverable reserves or not, or if there is an impairment, the costs are reclassified to the full cost pool.

The Company performs a ceiling test each quarter. The full cost ceiling test is a limitation on capitalized costs prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is not a fair value based measurement. Rather, it is a standardized mathematical calculation. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each cost center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices (as discussed below), excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, at a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax basis of oil and gas properties. The ceiling test is based on the average of the first-day-of-the-month prices during the prior twelve-month period. If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling, the excess shall be charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off shall not be reinstated for any subsequent increase in the cost center ceiling.

At July 31, 2012 and 2011, no ceiling test write-down was required.

3. STOCK-BASED COMPENSATION

For the nine months ended July 31, 2012 and 2011, the Company recognized stock based compensation expense of $15,000 and $47,000, respectively. For three months ended July 31, 2011, the Company recognized stock based compensation expense of $8,000. There was no expense for the three months ended July 31, 2012. At July 31, 2012, the balance of unrecognized compensation cost from unvested stock options was zero.

No options have been granted during the first nine months of fiscal year 2012. The fair value of the 30,000 options granted during the nine months ended July 31, 2011 was estimated as of the grant date using the Black-Scholes option pricing model with the following assumptions: volatility, 50.1%; expected option term, 4 years; risk-free interest rate, 2.28% 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 estimate will also be included in compensation expense.

Plan activity for the nine months ended July 31, 2012 is set forth below:

	Nine Months Ended July 31, 2012		
	Number of Options	Weighted Average Exercise Price	Aggregate Intrinsic Value
Outstanding at October 31, 2011	179,053	$ 8.40	$ 381,000
Granted			
Exercised			
Cancelled or forfeited	(50,000)	9.30	

Outstanding at July 31, 2012	129,053	$	8.05	$	823,000
Exercisable at July 31, 2012	129,053	$	8.05	$	823,000
Weighted average contractual life at July 31, 2012			1.95years		

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Range of Exercise Prices	Number Outstanding at July, 31, 2012	Outstanding Weighted Average Remaining Contractual Life in Years		Weighted Average Exercise Price	Exercisable Number Exercisable at July 31, 2012		Weighted Average Exercise Price
$ 5.93	89,053	0.87	$	5.93	89,053	$	5.93
$ 12.78	40,000	4.35	$	12.78	40,000	$	12.78
$ 5.93 -$12.78	129,053		$	8.05	129,053	$	8.05

During the nine months ended July 31, 2012, the Company purchased a stock option from its former CEO, a current director, for $31,000 because the option was going to expire during a stock trading blackout period. The stock option was for a right to purchase 33,334 shares of the Company s common stock. These options are included in the line item cancelled or forfeited in the table above. This amount is included in the consolidated balance sheet as a reduction in capital in excess of par value.

4. OIL AND NATURAL GAS DERIVATIVES

The Company manages exposure to commodity price fluctuations by periodically hedging a portion of estimated production when the potential for significant downward price movement is anticipated or to assure availability of cash flow for anticipated debt service. These transactions typically take the form of costless collars or forward short positions which are generally based upon the NYMEX futures prices. Hedge contracts are closed by purchasing offsetting positions. Such hedges are authorized by the Company s Board of Directors and do not exceed estimated production volumes for the months hedged. Contracts 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.

At July 31, 2012, the Company held short sales open derivative contracts for 5,000 barrels of oil for each production month of August 2012 through December 2012 with prices ranging from $91.95 to $92.21. During the quarter ended July 31, 2012, the Company offset one contract (1,000 barrels) per month at a price of $99.80 per barrel. The Company held no open derivative contracts for natural gas at July 31, 2012.

For the nine months ended July 31, 2012 and 2011, the Company had realized (losses) on derivatives of ($199,000) and ($174,000), respectively, and unrealized gains (losses) of $32,000 and ($497,000), respectively. For the quarters ended July 31, 2012 and 2011, the Company had realized gains (losses) on derivatives of $45,000 and ($96,000), respectively, and unrealized gains of $671,000 and $1,080,000, respectively.

At July 31, 2012, the Company had a hedging line of credit with its bank which is integrated with its overall credit agreement. See Note 5 for information regarding the Company credit agreement.

The Company has elected not to designate its commodity derivatives as cash flow hedges for accounting purposes. Accordingly, such contracts are recorded at fair value on the balance sheet and changes in fair value are recorded in the statement of operations as they occur. The location and amount of derivative fair values and related gain (loss) are indicated in the following tables:

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Derivatives not designated as hedging instruments:

	Balance Sheet Location	As of July 31, 2012	As of October 31, 2011
Crude Oil Swaps	Derivative Asset-Current	$ 40,000	$ 8,000

Amount of Gain or (Loss) Recognized in Income (Loss) on Derivatives not designated as hedging instruments:

		Nine Months Ended July 31, 2012	Nine Months Ended July 31, 2011
Crude Oil Swaps	Other Expense	$ (167,000)	$
Natural Gas Forward Positions	Other Income		79,000
Natural Gas Basis Positions	Other Expense		(20,000)
Crude Oil Collars	Other Expense		(730,000)

		Three Months Ended July 31, 2012	Three Months Ended July 31, 2011
Crude Oil Swaps	Other Income	$ 716,000	$
Crude Oil Collars	Other Income		984,000

5. REVOLVING CREDIT LINE

At the beginning of fiscal 2012, the Company expected to borrow between $7 million and $12 million to partially finance its drilling activities for the year. During the second quarter of 2012, the Company entered into a Revolving Credit Agreement (the Agreement) with its principal bank, Bank of Oklahoma, NA. The Agreement provides for a $25,000,000 credit facility. The Agreement will mature in December 2016. The credit availability under the Agreement is governed by a Borrowing Base, the determination of which is made semi-annually by the lender based on review of the Company s reserves at April 30 and October 31. The Borrowing Base under the Agreement could increase or decrease based on such determination. In addition to the semi-annual determinations, the Company and the lender each have discretion at any time, but not more often than once during a calendar year, to have the Borrowing Base redetermined. The initial $7 million Borrowing Base was increased to $9.3 million effective April 30, 2012, and is expected to be increased further as the Company pledges additional collateral.

The Company must elect between one of two interest rates as follows:

(i) a rate that is based on interest rates applicable to dollar deposits in the London interbank market (LIBOR Rate) plus 175 to 275 basis points, depending on Borrowing Base utilization; or

(ii) a rate based on the greatest of (a) the prime rate announced by the Bank of Oklahoma; or (b) the federal funds rate plus 1/2 of 1%.

The Agreement includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, mergers, and acquisitions, and also includes two financial covenants. The Company is required to maintain a financial covenant related to the current ratio, where consolidated current assets to consolidated current liabilities is not less than 1.0 to 1.0 at the end of any fiscal quarter.

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For purpose of the covenant calculation, consolidated current assets is increased by the amount available on the line of credit less any derivative gains or losses included in consolidated current assets or consolidated current liabilities. In addition, current liabilities are decreased by the amount of accrued, but unbilled, drilling and completion costs associated with an approved AFE as of the end of the quarter. The Company is also required to maintain a financial covenant related to consolidated funded indebtedness to consolidated EBITDAX, where the ratio at the end of any fiscal quarter is not greater than 3.5 to 1.0. This ratio is calculated using the twelve month period ending with the applicable fiscal quarter. If the Company were to fail to perform its obligations under these covenants or other covenants and obligations, it could cause an event of default and the Agreement could be terminated and amounts outstanding could be declared immediately due and payable by the lender, subject to notice and cure periods in certain cases. Such events of default include non-payment, breach of warranty, non-performance of financial covenants, certain adverse judgments, change of control, or a failure of the liens securing the Borrowing Base. As of July 31, 2012, the Company was in compliance with both covenant requirements, however, the current ratio calculation was very close to 1.0 to 1.0. If we fail to meet this ratio requirement in subsequent periods, and we are unable to obtain a waiver from the bank, it would trigger an event of default as described above.

The Company drew down $4 million on the line of credit during the three months ended July 31, 2012 and has drawn down $6 million during the nine months ended July 31, 2012 and that amount remains outstanding as of July 31, 2012. We are accruing interest at rates ranging from 2.75% to 3.49%, which are based on the LIBOR Rate at the time of the draw. We capitalized $33,000 and $44,000 of interest expense to the full cost pool during the three and nine months ended July 31, 2012. In addition to the amounts drawn down on the line of credit, the amount available on the Borrowing Base has been reduced by an additional $530,000 for Letters of Credit outstanding as of July 31, 2012 that are used in lieu of a cash bond to provide collateral for drilling programs. Subsequent to July 31, 2012, the Company drew down an additional $2.77 million on the line of credit to pay accounts payable related to drilling and completion costs.

6. 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 difference between the effective tax rate and the statutory tax rate is primarily due to percentage depletion deductions and costs incurred in the current fiscal year related to the Forestar merger, which are expected to be non-deductible expenditures for tax purposes.

The total future deferred income tax liability is 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.

The Company s Federal Income Tax Returns for fiscal years 2010, 2009 and 2008 have been audited by the IRS and the IRS Agent s Report has been received. The Agent s Report asserts multiple complex tax issues and potential additional tax due. The Company has appealed the assertions. Should the Company not prevail on the appeal, no additional tax would be due as NOL carry forwards would be applied to those years. However, a non-cash charge to earnings of approximately $215,000 could result on loss of all or part of the appeal. The Company believes the position of the IRS is without merit.

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7. FAIR VALUE MEASUREMENTS

The Company utilizes derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of its anticipated future oil and natural gas production. These derivatives are carried at fair value on the consolidated balance sheets. Additionally, the Company s short-term investments consist partially of professionally managed limited partnerships which include investments that are not publicly traded and may have less readily determinable market values. ASC Topic 820, *Fair Value Measurement and Disclosure,* establishes a valuation hierarchy for disclosure of the inputs to valuation used to measure fair value. This hierarchy prioritizes the inputs into three broad levels as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.
- Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

The classification of financial asset or liability within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The determination of the fair values below incorporates various factors required under fair value accounting guidance, including the impact of the counterparty s non-performance risk with respect to the Company s financial assets and the Company s non-performance risk with respect to the Company s financial liabilities.

The Company s only non-recurring fair value measurement is asset retirement obligations, as further described in Note 8. The Company determines the estimated fair value of its asset retirement obligations at the balance sheet date by calculating the present value of estimated cash flows related to plugging and abandonment liabilities using level 3 inputs. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company s credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted as a component of the full cost pool using the units-of-production method.

The following table provides the assets and liabilities carried at fair value measured on a recurring basis as of July 31, 2012:

	As of July 31, 2012			
	Level 1	**Level 2**	**Level 3**	**Total**
		(in thousands)		
Asset:				
Short-term investments	$ 380	$	$ 14	$ 394
Derivative Asset-Current	$	$ 40	$	$ 40

Level 3 instruments are comprised of the Company s investments in professionally managed limited partnerships. The fair value represents the net asset value of the Company s share in each partnership. The Company identified the investments as Level 3 instruments due to the fact that quoted prices for the underlying investments in the partnerships cannot be obtained and there is not an active market for the underlying investments or the partnerships shares. The Company utilizes the periodic fund statements along with current fund redemption activity and communication with investment advisors to determine the valuation of its investment. All of the Level 3 investments are in the process of liquidation, and redemption.

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The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the three and nine months ended July 31, 2012:

	Three Months Ended July 31, 2012	Nine Months Ended July 31, 2012
Balance as of April 30, 2012, and October 31, 2011(1), respectively	$ 14,000	$ 19,000
Total gains or losses (realized or unrealized):		
Included in earnings(2)		(5,000)
Redemptions		
Balance as of July 31, 2012(1)	$ 14,000	$ 14,000

(1) This amount is included in short term investments on the balance sheet.

(2) This amount is included in investment and other income (expense) on the statement of operations.

The Company s financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company s revolving credit facility approximated fair value because the facility s interest rate is variable (level 2 measurement).

8. ASSET RETIREMENT OBLIGATIONS

The Company estimates the future cost of asset retirement obligations, discounts that cost to its present value, and records an asset to evaluated oil and gas properties and a corresponding liability to asset retirement obligation in its consolidated balance sheets. The values ultimately derived are based on many significant estimates, including future abandonment costs, inflation, 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. A reconciliation of the Company s asset retirement obligation liability is as follows:

	July 31, 2012
Beginning asset retirement obligation	**$ 1,213,000**
Accretion expense	**54,000**
Obligations incurred	**320,000**
Obligations settled	**(143,000)**
Ending asset retirement obligation	**$ 1,444,000**

9. INTANGIBLE ASSETS

The patents underlying the Calliope Gas Recovery System are carried as a non-current asset on the Company s balance sheet and are being amortized over the average remaining life of the patents. The Company periodically evaluates this asset for realizability.

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	July 31, 2012	
	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets:		
Calliope intangible assets	$ 4,449,000	$ 1,634,000
Aggregate amortization expense:		
For the nine months ended July 31, 2012		$ 326,000

10. COMMON STOCK

On September 22, 2008, the Company s Board of Directors authorized a Stock Repurchase Program and approved repurchase of the Company s common stock up to $2,000,000. On April 9, 2009, the Board expanded the program to $4,000,000 and on July 29, 2010 the program was expanded to $5,000,000. The repurchases may be made on the open market, in block trades or otherwise. The stock repurchase program may be expanded, suspended or discontinued at any time. At July 31, 2012, the Company has acquired 545,429 shares under the program, at an aggregate cost of $4,755,000, or $8.72 per share.

Subsequent to July 31, 2012 and through September 10, 2012, no additional shares have been repurchased.

11. EARNINGS PER SHARE

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

	Nine Months Ended July 31,					
	2012			2011		
	Net Income	Shares	Earnings Per Share	Net Income	Shares	Earnings Per Share
Basic earnings per share	**$ 3,018,000**	**10,041,000**	**$ .30**	$ 2,131,000	10,042,000	$ .21
Effect of dilutive shares of common stock from stock options		**47,000**			36,000	
Diluted earnings per share	**$ 3,018,000**	**10,088,000**	**$ .30**	$ 2,131,000	10,078,000	$ .21

	Three Months Ended July 31,					
	2012			2011		
	Net Income	Shares	Earnings Per Share	Net Income	Shares	Earnings Per Share
Basic earnings per share	**$ 928,000**	**10,041,000**	**$ .09**	$ 1,707,000	10,041,000	$ .17
Effect of dilutive shares of common stock from stock options		**55,000**			31,000	

Diluted earnings per share	**$**	**928,000**	**10,096,000**	**$**	**.09**	$	1,707,000	10,072,000	$	.17

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12. CONCENTRATION OF CREDIT RISK

CREDO s accounts receivable are primarily from purchasers of the Company s oil and natural gas production and from other exploration and production companies which own joint working interests in the properties that the Company operates. This industry concentration could adversely impact the Company s overall credit risk, because the Company s customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices, and other conditions. CREDO s oil and gas production is sold to various purchasers in accordance with the Company s credit policies and procedures. These policies and procedures take into account, among other things, the creditworthiness of potential purchasers and concentrations of credit risk. For most joint working interest partners, the Company may have the right of offset against related oil and natural gas revenues. As of July 31, 2012, 79% of trade receivables on the consolidated balance sheets related to one joint working interest partner.

13. COMMITMENTS AND CONTINGENCIES

The Company has no material outstanding commitments at July 31, 2012.

The Company has filed a lawsuit for declaratory judgment regarding its contract rights under agreements with a third party related to its allotted lands Bakken and Three Forks leases. The third party has asserted certain counterclaims. The Company believes that the counter claims are without merit.

Between June 13, 2012 and July 27, 2012, five lawsuits were filed against the Company, Forestar, and each of the Company s directors by various stockholders. Two of the lawsuits were voluntarily dismissed by the plaintiffs. Two other lawsuits were consolidated into one proceeding, leaving two active lawsuits as of the date of this filing. The complaints allege, among other things, that the Company s directors breached their fiduciary duties to the Credo stockholders by agreeing to an inadequate price and issuing a materially misleading proxy statement, and that Forestar aided and abetted those breaches. The complaints seek an injunction, damages and attorneys fees. The Company, Forestar, and the Company s Board of Directors believe that the claims in the above complaints are entirely without merit and are defending the actions vigorously.

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

OPERATIONS

Summary

On June 3, 2012, the Company signed a merger agreement with Forestar Group Inc. (Forestar) pursuant to which Forestar will pay $14.50 for each share of the Company s stock, or approximately $146 million in cash. Consummation of the merger is not subject to a financing condition, but is subject to customary closing conditions, including the approval of Credo s stockholders. A special meeting of the Company s stockholders is scheduled to be held on September 25, 2012, at which stockholders will vote whether or not to approve the merger. The merger has been approved by the boards of directors of the Company and Forestar. Assuming the satisfaction of conditions, the merger could close prior to the Company s fiscal year-end. As the transaction remains subject to certain closing conditions, there can be no assurance that this merger will be consummated, therefore, this MD&A has been prepared under the assumption that the Company will continue under the current ownership structure. Additional information regarding the merger can be found in our Form 8-K filed on June 4, 2012 and our Definitive Proxy Statement filed on August 10, 2012.

During the first nine months of fiscal 2012, the Company s operations focused primarily on its oil drilling projects in the North Dakota Bakken and Three Forks shale-oil play and in Kansas, Nebraska and the Texas Panhandle. The Company expects these activities to be a reliable source of oil production and reserve additions. However, the timing and extent of such activities can be dependent on many factors which are beyond the Company s control, including for non-operated properties, the timing decisions of the well operators related to drilling, the availability of oil field services such as drilling rigs, fracture stimulation equipment and related services, and particularly in North Dakota, the weather. The price of oil and natural gas has a significant effect on the demand for, and cost of, drilling and oil field services.

The Company believes that its geographically and technically diverse oil drilling projects provide an excellent balance for achieving its goal of adding oil reserves and production at reasonable costs and risks. Horizontal drilling results are expected to occur relatively evenly due to the more developmental nature of the drilling. Vertical drilling results will occur less evenly due to the more exploratory nature of the projects.

Refer to the MD&A section of the Company s Annual Report on Form 10-K/A and particularly the subsection titled Certain Significant Effects of the Company s Strategic Transition to Oil from Natural Gas for more detailed information.

RESULTS OF OPERATIONS

Nine Months Ended July 31, 2012 Compared to Nine Months Ended July 31, 2011

For the nine months ended July 31, 2012, oil and gas revenues increased 53% to $18,043,000 compared to $11,806,000 during the same period last year. As the oil and gas price/volume table on page 20 shows, the Company s oil production increased 86% to 184,200 barrels while natural gas production declined 7% to 641,000 Mcf. Total production, at the six to one gas to oil energy equivalent conversion ratio, increased 36% to 291,100 barrels of oil equivalent (BOE), or 1,062 BOE per day. The increased total production volume resulted in a revenue increase of $7,198,000. For the nine months ended July 31, 2012, oil sales prices decreased 1% to $86.64 per barrel and natural gas sales prices decreased 28% to $3.26 per Mcf. The net effect of these price changes was to decrease oil and gas sales by $961,000.

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Total costs and expenses increased 59% to $13,236,000 compared to $8,310,000 for the same period last year. Transaction costs related to the Forestar merger were $1,026,000 during the nine months ended July 31, 2012. Total expenditures excluding these transaction costs would have been $12,210,000, or a 47% increase compared to the same period last year. Oil and gas production expenses increased 22% due to (i) increased production taxes on increased revenue which were partially offset by a production tax credit related to prior years, (ii) increased ad valorem taxes related to an increase in the number of wells subject to the tax, and (iii) increased lease operating expense due primarily to the addition of new wells during the reporting period. DD&A increased primarily due to property cost additions for future development costs of proved undeveloped Bakken and Three Forks reserves additions made starting in the fourth quarter of fiscal 2011. Refer to the MD&A section (Item 7) of the Company s Annual Report on Form 10-K/A for the fiscal year ended October 31, 2011 for additional information regarding Certain Significant Effects of the Company s Strategic Transition to Oil from Natural Gas . General and administrative expenses increased $1,518,000, or 75%, compared to prior year. As mentioned above, $1,026,000 of the increase related to one-time merger related costs including fairness opinions, legal expenses and proxy costs. Excluding merger related costs, general and administrative expenses increased $492,000, or 24%, compared to prior year due to increases in salary expense related to staff additions, one-time employment placement costs and professional fees primarily related to accounting and auditing services, partially offset by reduced legal fees related to a lawsuit that was settled in the prior year. The effective tax rate increased to 35% compared to 26% for the same period last year. The increase, required to be calculated on an annualized basis, is primarily due to the 1,000 barrel per day limitation on percentage depletion and the non-deductible merger related costs. As the Company s fiscal 2012 production grows beyond the 1,000 barrel per day tax limitation, as it did during the second and third quarters of 2012, percentage depletion will have a proportionately smaller impact on reducing the effective tax rate. For the nine month period, the total of realized and unrealized derivative losses on hedges decreased $504,000 because the differential between market prices at July 31, 2012 and the hedged prices for the related months narrowed significantly compared to the comparable period.

Three Months Ended July 31, 2012 Compared to Three Months Ended July 31, 2011

For the three months ended July 31, 2012, oil and gas revenues increased 42% to $6,362,000 compared to $4,488,000 during the same period last year. As the oil and gas price/volume table on page 20 shows, the Company s oil production increased 92% to 73,000 barrels while natural gas production declined 8% to 217,000 Mcf. Total production, at the six to one gas to oil energy equivalent conversion ratio, increased 41% to 109,200 BOE, or 1,187 BOE per day, resulting in a revenue increase of $2,671,000. For the three months ended July 31, 2012, oil sales prices decreased 12% to $78.00 per barrel and natural gas sales prices decreased 36% to $3.09 per Mcf. The net effect of these price changes was to decrease oil and gas sales by $797,000.

For the three months ended July 31, 2012, total costs and expenses increased 75% to $5,486,000 compared to $3,139,000 for the same period last year. Transaction costs related to the Forestar merger were $994,000 during the three months ended July 31, 2012. Total expenditures excluding these transaction costs would have been $4,492,000, or a 43% increase compared to the same period last year. Oil and gas production expenses increased 22% due to (i) higher production taxes related to increased revenue, (ii) increased ad valorem taxes related to an increase in the number of wells subject to the tax, and (iii) increased lease operating expense due primarily to the addition of new wells during the reporting period. DD&A increased primarily due to property cost additions for future development costs of proved undeveloped Bakken and Three Forks reserves additions made starting in the fourth quarter of fiscal 2011. Refer to the MD&A section (Item 7) of the Company s Annual Report on Form 10-K/A for the fiscal year ended October 31, 2011 for additional information regarding Certain Significant Effects of the Company s Strategic Transition to Oil from Natural Gas . General and administrative expenses increased $1,029,000, or 125%, compared to prior year. As mentioned above, $994,000 of the increase related to one-time merger related costs including fairness opinions, legal fees and proxy costs. Excluding merger related costs, general and administrative expenses increased $35,000, or 4%, compared to prior year due to

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increases in salary expense related to staff additions, partially offset by reduced legal fees related to a law suit that was settled in the prior year. The effective tax rate increased to 42% compared to 27% for the same period last year. The increase, required to be calculated on an annualized basis, is primarily due to the 1,000 barrel per day limitation on percentage depletion and the non-deductible merger related costs. As the Company s fiscal 2012 production grows beyond the 1,000 barrel per day tax limitation, as it did during the second and third quarters of 2012, percentage depletion will have a proportionately smaller impact on reducing the effective tax rate. For the three months ended July 31, 2012, the total of realized and unrealized derivative gains on oil hedges decreased $268,000 because the differential between the market prices at July 31, 2012 and the hedged prices for the related months narrowed compared to the comparable period.

LIQUIDITY AND CAPITAL RESOURCES

For the nine months ended July 31, 2012, oil and gas property costs increased $30,286,000, of which of $15,745,000 were paid in cash and $14,541,000 represents the increase in current liabilities from prior fiscal year end. At July 31, 2012, the Company had borrowed $6,000,000 on its line of credit, and subsequent to third quarter end, the Company borrowed an additional $2,770,000. The Company anticipates that existing cash on hand, net cash provided by operating activities and cash available under its line of credit will be adequate to fund the remainder of its 2012 capital expenditure program. Refer to the discussion below regarding capital expenditures and the company s credit facility.

Net cash provided by operating activities was $7,774,000 for the nine months ended July 31, 2012. Adjusted earnings before interest, taxes, depreciation, depletion and amortization, and unrealized derivative gains and losses, (Adjusted EBITDA) increased 59% to $10,792,000 compared to $6,778,000 for the same period last year. Adjusted 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 Adjusted EBITDA is not a GAAP measure, it may not necessarily be comparable to similarly titled measures employed by other companies. Reconciliation between Adjusted EBITDA and net income is provided in the table below:

	Nine Months Ended July 31, 2012	2011
RECONCILIATION OF ADJUSTED EBITDA:		
Net Income	**$ 3,018,000**	$ 2,131,000
Add Back:		
Income Tax Expense	**1,625,000**	749,000
Depreciation, Depletion and Amortization Expense	**6,181,000**	3,401,000
Unrealized Derivative (Gains)/Losses	**(32,000)**	497,000
ADJUSTED EBITDA	**$ 10,792,000**	$ 6,778,000

At July 31, 2012, the Company had a working capital deficit of $11,475,000 primarily due to drilling and completion costs related to its North Dakota Bakken and Three Forks drilling project. The Company expects that it will experience working capital deficits during periods when it is making use of outside financing because it will accrue estimated liabilities before the costs are billed by the operators and become payable. The Company will not draw down its line of credit until those costs are payable. This use of just-in-time financing will minimize the Company s borrowing costs but will also result in a working capital deficit during periods when the Company uses bank borrowing to finance a portion of its drilling budget.

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Capital expenditures are expected to almost double in fiscal 2012 to nearly $37,000,000 and, for the first time in the Company s history, financing was required to fund a portion of drilling expenditures. To provide financing, the Company established a revolving credit line with its principal bank which provides for a $25,000,000 credit facility. Credit availability is governed by a borrowing base which is determined semi-annually by the lender based on review of the Company s reserves at April 30 and October 31. The initial $7 million borrowing base was increased to $9.3 million during the second quarter, and will continue to be increased as the Company pledges additional collateral. As of July 31, 2012, the Company has drawn $6 million on the line of credit at interest rates ranging from 2.75% to 3.49%, and subsequent to quarter end, the Company drew down another $2.77 million on the line of credit.

In an attempt to reduce completion costs, some North Dakota operators have instituted a program of drilling multiple wells from the same pad, then fracing those wells successively. The cost savings are realized in reduced mobilization costs of manpower and equipment. This policy may add (on average) thirty days to the time between cessation of drilling operations and initial production, thus affecting the Company s cash flow as a non-operator. Accordingly, the Company expects that its 2012 borrowing requirements will be toward the upper end of the previously-announced $7.0 to $12.0 million range. However, this policy will positively affect long-term well economics. The company saw initial production on five North Dakota wells in the third quarter, and reasonably expects initial production on six additional wells in the fourth quarter, partly due to this multi-well frac program.

The Company has reported a working capital deficit in all three quarters of the current fiscal year. The primary reason for this is our aggressive 2012 drilling program. As part of the Revolving Credit Agreement with Bank of Oklahoma, we are required to be in compliance with two debt covenants, one of which is a current ratio covenant. The Company is required to maintain a financial covenant related to the current ratio, where consolidated current assets to consolidated current liabilities is not less than 1.0 to 1.0 at the end of any fiscal quarter. For purpose of the covenant calculation, consolidated current assets is increased by the amount available on the line of credit less any derivative gains or losses included in consolidated current assets or consolidated current liabilities. In addition, current liabilities are decreased by the amount of accrued, but unbilled, drilling and completion costs associated with an approved AFE as of the end of the quarter. The Company has been in compliance with this ratio throughout this fiscal year, however, the ratio as of July 31, 2012 was just above the minimum 1.0 to 1.0 ratio requirement. If we fail to meet this ratio in future periods, and are unable to obtain a waiver from the bank, it would cause an event of default and the Agreement could be terminated and amounts outstanding could be declared immediately due and payable by the lender, subject to notice and cure periods in certain cases.

The potential merger with Forestar has impacted our current ratio. We incurred $1,026,000 of one-time merger related costs through the first nine months of fiscal 2012. In addition, while we have the ability to pledge more properties to increase our Borrowing Base on the line of credit, which would be added to current assets as part of the current ratio, we have not proceeded as quickly as we anticipated due to the potential merger. The reason for this is that management made a decision not to incur the additional time and expense it would take to pledge our properties until the merger is completed. The Company has the capacity and the ability to increase the Borrowing Base and would do so if the merger is not completed.

Given our increased production and our ability to further increase the Borrowing Base, the Company believes that it will have sufficient cash to complete its 2012 drilling program, maintain a similar drilling plan in 2013 and continue to meet its covenant requirements included with the credit facility.

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.

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OFF-BALANCE SHEET FINANCING

The Company has no off-balance sheet arrangements at July 31, 2012.

PRODUCT PRICES AND PRODUCTION

The table below shows the Company s oil and gas production volumes and average wellhead prices for the reported periods. For the nine months ended July 31, 2012, oil represents 63% of total production (on an energy equivalent basis) compared to 46% for the prior year. For the three months ended July 31, 2012, oil represents 67% of total production compared to 49% for the same period last fiscal year. Wellhead prices do not include oil derivative gains and losses since the Company has elected not to designate derivative instruments as cash flow hedges.

	Nine Months Ended July 31,								
	2012			2011			% Change	
Product	**Volume**		**Price**	**Volume**		**Price**	**Volume**	**Price**
Oil (bbls)	**184,200**	**$**	**86.64**	99,200	$	87.49	+ 86%	- 1%
Gas (Mcf)	**641,000**	**$**	**3.26**	690,000	$	4.53	- 7%	- 28%
BOE (Barrels of Oil Equivalent)	**291,100**			214,300			+ 36%	
BOE per Day	**1,062**			785				

	Three Months Ended July 31,							
	2012			2011			% Change	
Product	**Volume**		**Price**	**Volume**		**Price**	**Volume**	**Price**
Oil (bbls)	**73,000**	**$**	**78.00**	38,000	$	88.32	+ 92%	- 12%
Gas (Mcf)	**217,000**	**$**	**3.09**	235,000	$	4.81	- 8%	- 36%
BOE (Barrels of Oil Equivalent)	**109,200**			77,200			+ 41%	
BOE per day	**1,187**			839				

Although product prices are key to the Company s ability to operate profitably and to budget capital, income and expenses, they are beyond the Company s control and are difficult to predict. The Company periodically hedges the price of a portion of its estimated production when the potential for significant downward price movement is anticipated, or to assure availability of a portion of the cash flow for anticipated debt service. Such hedges are authorized by the Company s Board of Directors and they do not exceed estimated production volumes for the periods hedged. Hedging transactions may take the form of costless collars or forward short positions, and are generally based on the NYMEX futures prices at the time the transactions are initiated. The positions are normally closed by purchasing offsetting positions. Contracts 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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For the nine months ended July 31, 2012, realized hedging losses were $199,000 compared to $174,000 last year. The effect of realized derivative losses on average well head price realizations are shown in the following table:

	Nine Months Ended July 31,					
		2012			2011	
Product	Price	Realized Derivative Gain (Loss)	Effective Price Realization	Price	Realized Derivative Gain (Loss)	Effective Price Realization
Oil	$ 86.64	$ (1.08)	$ 85.56	$ 87.49	$ (2.36)	$ 85.13
Gas	$ 3.26	$	$ 3.26	$ 4.53	$ 0.09	$ 4.62

For the three months ended July 31, 2012, realized hedging gains were $45,000 compared to realized hedging losses of $96,000 last year. The effect of realized derivative gains and losses on average well head price realizations are shown in the following table:

	Three Months Ended July 31,					
		2012			2011	
Product	Price	Realized Derivative Gain (Loss)	Effective Price Realization	Price	Realized Derivative Gain (Loss)	Effective Price Realization
Oil	$ 78.00	$ 0.61	$ 78.61	$ 88.32	$ (2.53)	$ 85.79
Gas	$ 3.09	$	$ 3.09	$ 4.81	$	$ 4.81

At July 31, 2012, the Company held open short sales derivative contracts for 5,000 barrels of oil (five contracts) for each production month of August 2012 through December 2012 with prices ranging from $91.95 to $92.21. This hedge is expected to cover approximately 15% to 25% of estimated oil production for the hedged period. During the three months ended July 31, 2012, the Company closed one contract per month at a price of $99.80 per barrel.

See Note 4 of the Notes to Consolidated Financial Statements and comments under MD&A, Results of Operations , for more information regarding hedging gains and losses relating to oil derivative instruments.

RECENT DRILLING ACTIVITIES

Capital expenditures for fiscal 2012 are now expected to be approximately $37,000,000 compared to our original budget of $35,000,000, of which approximately 95% will have been earmarked for drilling and completion activities. By the end of fiscal 2012, the Company expects to have drilled seventy five (75) gross (30 net) oil wells. During the first nine months of 2012, 56 gross (23 net) wells were drilled and completed or were in various stages of drilling and completion. The regional allocation of the Company s capital expenditures is shown below (in millions).

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	Nine Months 2012 Actual	2012 Annual Budget	2011 Actual
North Dakota Bakken and Three Forks	$ 19.1	$ 22.4	$ 6.6
Kansas and Nebraska Lansing Kansas City	7.9	9.8	8.4
Texas Panhandle Tonkawa and Cleveland	1.8	1.4	2.0
Other (primarily Oklahoma natural gas)	1.5	1.4	1.7
	$ 30.3	$ 35.0	$ 18.7

Approximately 65% of drilling expenditures in the current fiscal year will be spent on the Bakken and Three Forks project. Because the Company is not in control of the timing of the project s drilling operations, it cannot reasonably predict the timing and extent of drilling costs until the operators actually propose wells. Accordingly, the Company s fiscal 2012 drilling budget attempted to estimate drilling schedules through discussions with operators before wells are actually proposed. As a result, the Company s fiscal 2012 drilling schedule and drilling budget have been and continue to be subject to significant revision as more information becomes available regarding the actual timing and costs of drilling. In general, the Company expects its Bakken and Three Forks drilling to continue to accelerate through the remainder of fiscal 2012 and into fiscal 2013.

Bakken and Three Forks Project In the North Dakota s Bakken and Three Forks shale-oil play, the Company has assembled an approximate 9% average working interest in 73,000 gross acres (based on interests in approximately 57 spacing units consisting of 1,280 acres). Virtually all of the acreage is located in the core of the play on the Fort Berthold Reservation, south and west of Parshall Field. Fifty of the spacing units are classified as prime. The Company believes that a minimum of two Bakken and two Three Forks wells are likely to be drilled on most of the prime spacing units representing about 200 wells. However, many of the larger Bakken operators predict that up to eight wells may be drilled in many spacing units, which could double potential Company wells.

Drilling on the Company s acreage continues to increase. A total of 23 Bakken and Three Forks wells are budgeted for fiscal 2012, of which 19 wells are currently being drilled or completed and an additional 4 wells are scheduled for drilling before fiscal year end. By fiscal year-end, the Company expects to own interests in 39 total wells, consisting of 28 Bakken and 11 Three Forks wells. All of the wells currently drilled and completed by the Company are high rate producers.

The Company is participating as a non-operator with highly experienced Bakken operators. In all cases, where a well has been drilled on a spacing unit, the Company expects additional development wells to be drilled on those spacing units.

The Company s Bakken and Three Forks acreage position is subject to agreements with a third party which grants the third party an option to purchase between 5% and 10% of the Company s interest in individual leases under certain specified circumstances.

Kansas and Nebraska The Company currently owns approximately 131,800 gross (87,000 net) acres in Kansas and Nebraska and is conducting an aggressive leasing and drilling project. The project consists primarily of wildcat oil drilling based on subsurface geology which is generally confirmed by 3-D seismic. To date, the Company has participated in 139 gross (57.2 net) wells with an average 41% working interest. The Company s overall drilling success rate is about 40%, yielding all in risk adjusted internal rates of return (at current oil prices) of approximately 100%. Wells are drilled to a vertical depth of 4,000 to 5,000 feet. Based on having proved its technical concepts in Kansas and Nebraska, the Company believes the project is now scalable and repeatable.

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Four new 3-D seismic shoots are scheduled to be completed in Kansas and Nebraska by fiscal year end which will cover about 66 square miles. During fiscal 2012, the Company estimates that it will participate in 46 gross (27.7 net) wells in Kansas and Nebraska with an average working interest of approximately 60%. During the third quarter of 2012, the Company participated in 11 gross (6.2 net) wells with an average 56.4% working interest. The Company will be the operator of approximately 70% of the Kansas and Nebraska wells expected to be drilled in fiscal 2012.

Texas Panhandle In the Texas Panhandle, the Company owns 8,500 gross (2,400 net) acres with the potential for multi-pay horizontal and vertical drilling. The acreage includes six 640 acre spacing units that are prospective for Tonkawa and Cleveland horizontal drilling and Morrow vertical drilling. The Company believes that each spacing unit could ultimately contain two Tonkawa and two Cleveland wells.

The Company currently owns an average 29% working interests in two gross (0.5 net) producing horizontal Tonkawa wells which continue to be good producers. The Company recently completed its first horizontal Cleveland well with a 25% working interest and is currently evaluating offset potential. It also owns interests in 12 gross (.9 net) producing vertical wells with an average working interest of 7%.

The Company believes its acreage holds potential for up to 25 horizontal Tonkawa and Cleveland wells, in addition to three vertical Morrow wells. The Company estimates its average working interest in these wells to range between 25% and 30%.

Oklahoma Natural gas drilling in Oklahoma has been suspended pending a recovery in natural gas prices. Accordingly, no gas wells are projected for Oklahoma during 2012. Most of the Company s Oklahoma acreage is held by production and, thus, the timing of drilling is not critical to maintaining the Company s leasehold ownership.

Calliope Gas Recovery Technology The Company is taking advantage of opportunities created by low natural gas prices to buy wells for application of its patented Calliope Gas Recovery System. A team is dedicated to Calliope with the objective of acquiring Calliope candidates, as companies de-emphasize natural gas and offload gas properties while shifting to oil development.

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 include, among other things, statements relating to:

- the Company s future financial position, including working capital and anticipated cash flow;
- amounts and nature of future capital expenditures;

- projections of operating costs and other expenses;
- wells to be drilled or reworked including new drilling expectations;
- expectations regarding oil and natural gas prices and demand;
- existing fields, wells and prospects;
- diversification of exploration, capital exposure, risk and reserve potential of drilling activities;
- estimates of proved oil and natural gas reserves;
- expectations and projections regarding joint ventures;
- reserve potential;
- development and drilling potential;

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- expansion and other development trends in the oil and natural gas industry;
- the Company s business strategy;
- production and production potential of oil and natural gas;
- matters related to the Calliope Gas Recovery System, including projections for future use of Calliope and the success of Calliope;
- effects of federal, state and local regulation;
- the outcome of judicial or regulatory proceedings
- adequacy of insurance coverage;
- employee relations;
- effectiveness of the Company s hedging transactions;
- investment strategy and risk; and
- expansion and growth of the Company s business and operations.

Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. Disclosure of important factors that could cause actual results to differ materially from the Company s expectations, or cautionary statements, are included under Risk Factors in our Annual Report on Form 10-K/A. The following factors, among others, could cause actual results to differ materially from the Company s expectations:

- unexpected changes in business or economic conditions;
- significant changes in natural gas and oil prices;
- timing and amount of production;
- unanticipated down-hole mechanical problems in wells or problems related to producing reservoirs or infrastructure;
- changes in overhead costs;
- material events resulting in changes in estimates; and
- competitive factors.

All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on the Company s behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of anticipated or unanticipated events or circumstances.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company manages exposure to commodity price fluctuations by periodically hedging a portion of estimated production when the potential for significant downward price movement is anticipated or to assure availability of cash flow for anticipated debt service. These transactions typically take the form of costless collars or forward short positions which are generally based upon the NYMEX futures prices. Hedge contracts are closed by purchasing offsetting positions. Such hedges are authorized by the Company s Board of Directors and do not exceed estimated production volumes for the months hedged. Contracts 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.

For further discussion, see Note 4 to the Consolidated Financial Statements.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of Michael D. Davis, our Interim Chief Executive Officer, and Brian C. Mazeski, our Chief Accounting Officer, evaluated the effectiveness of our disclosure controls and procedures as of July 31, 2012. Based on the evaluation, these officers have concluded that:

Our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms; and

Our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 was accumulated and communicated to our management, including our Interim Chief Executive Officer and Chief Accounting Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that related to our last fiscal quarter that has materially affected or is reasonably likely to materially affect our internal control over financial reporting, except as follows:

As we disclosed in our Annual Report on Form 10-K/A for the fiscal year ended October 31, 2011 and in our Quarterly Report on Form 10-Q/A for the first quarter ended January 31, 2012, both of which we filed on April 25, 2012, we determined that there was a material weakness in our internal controls over financial reporting related to our liabilities accrual process that resulted in certain liabilities not being properly estimated and accrued by the Company at October 31, 2011 and January 31, 2012. Such liabilities consisted primarily of the Company s share of well drilling and completion costs which were incurred by third party well operators during the fiscal year ended October 31, 2011 and the three month period ended January 31, 2012 but were not timely billed to the Company. When this matter was identified in March 2012 for the October 31, 2011 and January 31, 2012 reporting periods, remediation procedures were put in place to better identify sources of potentially significant bills, including primarily those related to our Bakken project. The remediation consisted primarily of improved processes for making accrual estimates under certain conditions, including: obtaining daily drilling reports from operators of high cost wells and making a comparison of costs incurred as shown on the daily drilling report with related costs paid or accrued through the end of the reporting period; comparing costs accrued to authorizations for expenditure; discussing in more detail well operations with Company engineers; and contacting operators for additional information related to the expenditures. We implemented these procedures effective with the filings on April 25, 2012 and believe that they will be sufficient to provide materially accurate estimates of accrued liabilities. However, the material weakness will not be considered remediated until the applicable remedial controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Company has filed a lawsuit for declaratory judgment regarding its contract rights under agreements with a third party related to its allotted lands Bakken and Three Forks leases. The third party has asserted certain counterclaims. The Company believes that the counter claims are without merit.

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Between June 13, 2012 and July 27, 2012, five lawsuits were filed against the Company, Forestar, and each of the Company s directors by various stockholders. Two of the lawsuits were voluntarily dismissed by the plaintiffs. Two other lawsuits were consolidated into one proceeding, leaving two active lawsuits as of the date of this filing. The complaints allege, among other things, that the Company s directors breached their fiduciary duties to the Credo stockholders by agreeing to an inadequate price and issuing a materially misleading proxy statement, and that Forestar aided and abetted those breaches. The complaints seek an injunction, damage s and attorneys fees. The Company, Forestar, and the Company s Board of Directors believe that the claims in the above complaints are entirely without merit and are defending the actions vigorously.

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/A for the fiscal year ended October 31, 2011.

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

Issuer Purchases of Equity Securities.

On September 22, 2008, the Company s Board of Directors authorized a Stock Repurchase Program and approved repurchase of the Company s common stock up to $2,000,000. On April 9, 2009, the Board expanded the program to $4,000,000 and on July 29, 2010 the program was expanded to $5,000,000. The repurchases may be made on the open market, in block trades or otherwise. The stock repurchase program may be expanded, suspended or discontinued at any time. At July 31, 2012, the Company has acquired 545,429 shares under the program, at an aggregate cost of $4,755,000, or $8.72 per share.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

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 Accounting Officer under Section 302 of the Sarbanes-Oxley Act of 2002

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

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EX-101.INS	XBRL Instance Document
EX-101.SCH	XBRL Taxonomy Extension Schema document
EX-101.CAL	XBRL Taxonomy Extension Calculation Linkbase document
EX-101.DEF	XBRL Taxonomy Extension Definition Linkbase document
EX-101.LAB	XBRL Taxonomy Extension Labels Linkbase document
EX-101.PRE	XBRL Taxonomy Extension Presentation Linkbase document

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/ Michael D. Davis. Michael D. Davis Chief Executive Officer (Interim) (Principal Executive Officer)
By:	/s/ Brian C. Mazeski Brian C. Mazeski Chief Accounting Officer (Principal Financial and Accounting Officer)

Date: September 10, 2012