Growth Through Oil-Focused Drilling

CREDO Petroleum Corporation

2010 Annual Report

Corporate Profile

Credo Petroleum Corporation is an oil and gas independent exploration, development and production company based in Denver, Colorado. The company has significant operations in North Dakota's Bakken play, the Texas Panhandle, Oklahoma, Kansas and Nebraska. Credo utilizes advanced technologies, including 3-D seismic, horizontal drilling and multi-stage, high pressure fracturing, to systematically explore for oil and gas. In addition, the company's patented Calliope Gas Recovery System is used to revitalize old gas wells and recover stranded reserves from depleted gas reservoirs.

Credo has built good momentum in several outstanding oil plays and is now well-positioned to achieve substantial organic growth through oil-focused drilling.

2010 Highlights

- Record oil sales revenue represents 59% of total revenue
- Total oil and gas revenue increased 15% to $11,566,000
- Oil reserves increased to record 954,000 barrels
- First three of five horizontal Bakken wells producing; two awaiting completion
- First Texas Panhandle horizontal Tonkawa well in completion phase
- Central Kansas Uplift drilling success rate about 40% after 69 wells

Financial Data		**2010**		2009		2008
Income (Loss) Per Share — Diluted	**$**	**0.22**	$	(1.40)	$	0.61
Oil & Gas Revenues	**$**	**11,566,000**	$	10,067,000	$	17,345,000
Non-Cash Impairment & Write-off of Oil & Gas Properties	**$**	**—**		(24,653,000)		—
Working Capital	**$**	**9,661,000**	$	13,542,000	$	24,160,000
Shareholders' Equity	**$**	**46,567,000**	$	46,056,000	$	62,211,000
Total Assets	**$**	**53,405,000**	$	52,552,000	$	80,560,000
Common Shares Outstanding		**10,059,000**		10,241,000		10,437,000

Forward Looking Statements

Forward-looking statements are made in this Annual Report to give the reader an indication of our business prospects, plans and objectives, and include statements relating to, among other things, our business strategy, success of new projects, expansion and growth of production and reserves, anticipated number of wells to be drilled, commencement date of drilling, drilling costs, growth, benefits and success of Calliope and reserve targets. Although we believe these statements are reasonable at this time, actual results, performance or achievements could differ materially from those stated. Readers should refer to the risks involved in making these statements, which are given on page 7 of our Form 10-K, contained herein.

Dear Shareholders:

The theme of last year's annual report was "Building Momentum in Oil Plays". This year's theme, "Growth Through Oil-Focused Drilling", defines Credo today—as we embark on the most aggressive drilling schedule in company history in order to exploit oil's significant price advantage over natural gas. We have built good momentum in several outstanding oil plays, and Credo is now well-positioned to achieve substantial organic growth by significantly ramping-up our oil drilling operations.

Credo had a good year despite encountering some strong headwinds in 2010, such as a 27% drop in realized natural gas prices and production delays due to shortages of fracture stimulation equipment for horizontal wells. Highlights included a 15% revenue increase, with oil accounting for 59% of our total production revenue. Net income increased 277% to $2,203,000, compared to adjusted net income of $584,000 in 2009. We ended the year in very strong financial condition with significant operating cash flow and a rock-solid balance sheet, including ample cash and no debt. That enables us to enter 2011 with a significantly expanded drilling program and to seize opportunities that will propel future growth.

Business Strategy. Credo's business has undergone very significant changes over the last few years to implement your Board's decision to move away from natural gas and focus on building oil production and reserves. Our Board identified the opportunity and made that decision in 2008, well ahead of industry competition. That strategy proved both timely and correct, as oil is currently worth three times more than natural gas on an energy equivalent basis. In order to deliver outstanding results to our shareholders, we must own high quality assets that deliver profitability. We can exploit the significant value gap between oil and natural gas to dramatically benefit our bottom line by adding high-margin oil reserves in diversified plays through organic growth, and by making opportunistic acquisitions.

Utilizing new technology is a key part of our business strategy to find and produce oil. We are employing advanced 3-D seismic technology to help locate previously hidden but very economically attractive shallow oil deposits in Kansas and Nebraska. We are also utilizing the latest advances in precision horizontal drilling and multi-stage, high pressure fracture stimulation technology to develop oil reserves in deeper plays, both conventional and non-conventional, such as the North Dakota Bakken and the Texas Panhandle Tonkawa.

Drilling and Exploration. Credo has assembled approximately 8,000 gross (6,000 net) acres in the core of the nation's premier oil resource play, the North Dakota Bakken. Our acreage is located primarily on the Fort Berthold Reservation and consists of approximately 50 initial well spacing units. We expect that more than one well will be drilled on many of the spacing units. The acreage is highly prospective for both the Bakken and Sanish/Three Forks formations.

Recently, the company completed its third consecutive high-rate Bakken discovery and, to date has drilled five wells in the play, three of which are producing and two that are awaiting completion for production. One of our Bakken discoveries was drilled following an opportune acreage acquisition outside the Reservation. The reported rate of 2,278 barrels per day of oil equivalent is confirmed to be the highest initial test rate of any Credo well. We expect to participate in eleven Bakken wells in 2011, with varying working interests. Reserve estimates for the play have been increasing steadily as technology and know-how improves. The North Dakota Department of Mineral Resources recently indicated that the Bakken and Sanish/Three Forks plays could reasonably contain 11 billion barrels of recoverable oil.

In Kansas, Credo has achieved excellent drilling results on the Central Kansas Uplift. As of October 31, 2010, the company has participated in 69 wells on the Uplift, of which over 40% have been successfully completed as producers. Utilizing advanced 3-D seismic technology, Credo has developed a successful and repeatable exploration model. Accordingly, we are significantly ramping-up our drilling activity in Kansas, where we are currently drilling two to three wells per month with working interests ranging from 12.5% to 95%.

We are also developing new oil projects in southwest Nebraska, an extension of the Central Kansas Uplift. This is fertile ground for the company to expand our successful exploration model for shallow oil at moderate costs. In Kansas and Nebraska, Credo owns interests in approximately 147,000 gross (85,000 net) acres.

A new horizontal oil play, the Tonkawa, is unfolding for Credo in the Texas Panhandle, where we own an average 33% in about 3,000 gross acres. The company is currently drilling its second horizontal Tonkawa well, which will have an approximate 5,000-foot lateral. Our Texas Panhandle acreage is in a multi-pay environment, where Credo already operates twelve vertical wells. In addition to the Tonkawa, the horizontal Cleveland oil play is also highly prospective.

Calliope. All of us at Credo remain firm believers in our Calliope Gas Recovery System. An installation is now in process in Oklahoma and additional wells are being targeted for this proven technology. In addition, we are beginning to see Calliope interest from new players with fresh ideas as rapidly growing international companies seek innovative solutions to capture energy reserves. Monetizing Calliope's value remains a top company priority.

The Future. Credo has the operating cash flow, balance sheet, and drilling projects to thrive. Our transition into oil plays has been perfectly timed, and a supportive Board of Directors has embraced an aggressive oil drilling schedule that realistically provides the capacity to deliver significant organic growth in the near term. Our talented technical team is embracing the latest advances in exploration, drilling, and completion technologies to facilitate long-term, profitable growth. Our balanced portfolio of oil and gas assets and commitment to financial discipline will provide the flexibility to respond to new opportunities.

In closing, thank you for your continued loyalty and support. We are always mindful of our duty to uphold the trust you have placed in us through your ownership of Credo shares.

Marlis E. Smith, Jr.
Chief Executive Officer
February 15, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For The Fiscal Year Ended October 31, 2010

or

___ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF 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)	(I.R.S. Employer Identification Number)

1801 Broadway, Suite 900, Denver, Colorado 80202-3837
(Address of principal executive offices and zip code)

Registrant's telephone number, including area code: (303) 297-2200

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act:

Common Stock, $.10 Par Value
(Title of class and shares outstanding)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act: _____ Yes X No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act: _____ Yes X No

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. X Yes _____ No

Indicate by checkmark 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 _____ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (S229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

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 definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer __ Accelerated filer X Non-accelerated filer __ Smaller reporting company __

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of April 30, 2010, the end of the registrant's most recently completed second quarter was $70,031,000.

As of January 4, 2011, the registrant had 10,043,000 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Pursuant to instruction G (3) to Form 10-K, Items 10, 11, 12, 13 and 14 are omitted because the company will file a definitive proxy statement (the "Proxy Statement") pursuant to Regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year. The information required by such items will be included in the Proxy Statement to be so filed for the company's annual meeting of shareholders to be held on or about April 7, 2011 and is hereby incorporated by reference.

NON-GAAP FINANCIAL MEASURES

In this Annual Report on Form 10-K, the company uses the term "EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization including impairment losses)" which is considered a non-GAAP financial measure as defined in SEC Regulation S-K Item 10 and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with GAAP. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a definition of this measure as used in this Annual Report on Form 10-K.

Estimated Future Net Revenues Discounted at 10% is not a GAAP measure of operating performance. 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. See Item 2 PROPERTIES, Significant Properties, Estimated Proved Oil and Gas Reserves, and Future Net Revenues for a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note 12 to the company's Consolidated Financial Statements.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K 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 Annual Report on Form 10-K, 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;
- 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;
- adequacy of insurance coverage;
- employee relations;
- 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" and elsewhere in this Annual Report on Form 10-K, including, without limitation, in conjunction with the forward-looking statements. The following factors, among others that could cause actual results to differ materially from the company's expectations, include:

- 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.

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PART I

ITEM 1. BUSINESS

General

Credo Petroleum Corporation ("Credo") was incorporated in Colorado in 1978 and reincorporated in Delaware in 2009. Credo and its wholly owned subsidiaries, SECO Energy Corporation and United Oil Corporation ("SECO", "United" and collectively "the company"), are Denver, Colorado based independent oil and gas companies which engage primarily in oil and gas exploration, development and production activities in the Mid-Continent and Rocky Mountain areas of the United States. The company has operating activities in nine states and has thirteen full-time employees. Credo is an active operator in Kansas, Wyoming, Colorado and Texas. United is an active operator doing business primarily in Oklahoma, and SECO primarily owns royalty interests in the Rocky Mountain region. References to years as used in this report indicate fiscal years ended October 31.

Business Activities

Credo is engaged in the exploration for, acquisition of, and production of crude oil, natural gas and natural gas liquids. The company's business strategy focuses on two core areas: drilling for oil and natural gas and recovering stranded gas from low-pressure reservoirs using the company's patented Calliope Gas Recovery System ("Calliope"). Together, the company believes that drilling and Calliope provide a unique formula for success which distinguishes Credo from other oil and gas exploration and production companies.

Historically, the company's core drilling region was the northern shelf of the Anadarko Basin in Oklahoma where it explored primarily for natural gas. As a result, the company's reserves have historically been comprised mostly of natural gas.

In recent years, the company has made significant strategic changes with the objectives of expanding the volume and breadth of its drilling activities and focusing on drilling for and developing crude oil reserves. To accomplish these objectives, the company implemented new conventional exploration projects in central and western Kansas and Nebraska, and new horizontal exploration prospects in the North Dakota Bakken and the Texas Panhandle. This strategic change is intended to diversify the company's drilling projects both technologically and geographically and to improve the balance between crude oil and natural gas in both its production and reserves. Depending on natural gas prices, the company will continue generating prospects and drilling on its core natural gas-prone acreage in Oklahoma, concentrating on medium depth properties.

Compared to conventional drilling, the horizontal drilling projects in the North Dakota Bakken and the Texas Panhandle involve higher costs but have significantly higher per well reserve potential.

The company owns the patents covering Calliope and has been instrumental in developing, testing, refining, and patenting the technology. Calliope efficiently lifts fluids from wellbores using pressure differentials, thus allowing gas previously trapped by fluid build-up in the wellbore to flow to the surface. Calliope is distinguished from other fluid lift technologies because it does not rely on bottom-hole pressure and has only one down-hole moving part. Calliope is primarily applicable to mature natural gas wells in low pressure, natural gas expansion reservoirs at depths below 8,000 feet. External sources of capital have not been required for the development, refinement or installation of Calliope. The company has proven Calliope's economic viability and flexibility over a wide range of applications.

The company currently has Calliope installed on wells located in Oklahoma and Texas which include both sandstones and limestones in the Chester, Cotton Valley, Edwards, Hart, Hunton, Morrow, Nodosaria, Red Fork and Springer reservoirs.

Calliope's low per-unit finding and production costs have become increasingly attractive as the economics on many drilling projects have deteriorated due to lower product prices. The company also believes that lower natural gas prices may stimulate divestitures of marginal properties by other companies, including properties that have Calliope potential.

The company acts as "operator" of approximately 102 wells pursuant to standard industry operating agreements. The company owns working interests in about 305 producing wells and overriding royalty interests in about 1,200 wells.

Refer to Item 2., "Properties" and to "Drilling" in MD&A, for more information regarding the company's properties, its drilling projects, and Calliope.

Markets and Customers

Marketing of the company's oil and gas production is influenced by many factors which are beyond the company's control, and the exact effect of which cannot be accurately predicted. These factors include changes in supply and demand, speculation, market prices, regulation, and actions of major foreign producers.

Oil price fluctuations can be extremely volatile as was demonstrated when, during 2008, the posted price for West Texas intermediate in July reached more than $140 per barrel, then fell below $35 in December. Oil prices have since recovered to the $85 to $90 per barrel range. Oil production is generally sold to crude oil purchasing companies under one year contracts at competitive field prices. Crude oil and condensate production are readily marketable, and the company is generally not dependent on a single purchaser. Crude oil prices are subject to world-wide supply and demand, and are primarily dependent upon available supplies which can vary significantly depending on production and pricing policies of OPEC and other major producing countries and on significant events, such as wars, in major producing regions.

Natural gas price decontrol, the advent of an active spot market for natural gas, changes in supply and demand for natural gas, speculation, and weather patterns cause natural gas prices to be subject to significant fluctuations. The company presently sells virtually all of its natural gas under three to five year contracts with major pipeline companies. The sales price is typically based on monthly index prices for the applicable pipeline. Title to the natural gas normally passes to the pipeline at meters located near the wells. The index prices are reduced by certain pipeline charges.

Most of the company's natural gas production is located in northwestern Oklahoma. There has been significant consolidation among natural gas pipelines in this area, thereby reducing the number of available purchasers. In many instances, there may be only one viable pipeline option, which enables the pipeline to charge higher rates.

Natural gas prices were strong through mid-2008 due to concern about possible domestic supply/demand imbalances and in sympathy with increasing oil prices. This, together with supply vulnerability to natural disasters, such as hurricanes, and active speculation in the natural gas futures market caused natural gas prices to become increasingly volatile. The economic downturn that commenced in the second half of 2008 resulted in a significant reduction in industrial demand for natural gas at the same time gas supplies were significantly increasing due to horizontal drilling success in gas resource plays. Those events caused an over supply of natural gas with the result that prices crashed. For example, the Panhandle Eastern Pipeline natural gas index, the basis for most of the company's gas sales, fell from $11.07 per Mcf in July 2008 to $2.81 in November 2008, $3.50 in October 2009, and $3.55 in October 2010. The company cannot reasonably predict the extent or timing of natural gas price fluctuations.

As discussed elsewhere in this Annual Report on Form 10-K, the company periodically hedges the price of a portion of its estimated natural gas production in the form of forward short positions on the NYMEX futures market and hedges a portion of its estimated oil production generally in the form of costless collars.

Information concerning the company's major customers is included in Note (12) to the Consolidated Financial Statements.

Competition and Regulation

The oil and gas industry is highly competitive. As a small independent, the company must compete against companies with substantially greater financial, human and other resources in all aspects of its business.

Oil and gas drilling and production operations are regulated by various federal, state and local agencies. These agencies issue binding rules and regulations which carry penalties, often substantial, for failure to comply. The company anticipates its aggregate burden of federal, state and local regulation will continue to increase, particularly in the area of rapidly changing environmental laws and regulations. The company also believes that its present operations substantially comply with applicable regulations. There are no known environmental or other regulatory matters related to the company's operations which are reasonably expected to result in material liability to the company. The company believes that capital expenditures related to environmental control facilities or other regulatory matters will not be material in 2011. The company cannot predict what subsequent legislation or regulations may be enacted or what effect they might have on the company's business.

ITEM 1A. RISK FACTORS

In evaluating the company, careful consideration should be given to the following risk factors, in addition to the other information included or incorporated by reference in this Annual Report on Form 10-K. Each of these risk factors could adversely affect the company's business, operating results and financial condition, as well as adversely affect the value of an investment in the company's common stock.

Volatility of oil and natural gas prices could adversely affect the company's profitability and financial condition.

The company's performance in terms of revenues, operating results, profitability, future rate of growth and the carrying value of its oil and natural gas properties is significantly impacted by prevailing market prices for oil and natural gas. Any substantial or extended decline in the price of oil or natural gas could have a material adverse effect on the company. It could reduce the company's operating cash flow as well as the value and, to a lesser degree, the quantity of its oil and natural gas reserves. See the table of oil and gas sales volumes and prices on page 25 for further information.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile. Relatively minor changes in supply or demand can have a significant effect on oil and natural gas prices. Some of the factors affecting oil and natural gas prices which are beyond the company's control include:

- worldwide and domestic supplies of oil and natural gas;
- worldwide and domestic demand for oil and natural gas;
- the ability of the members of OPEC to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil or natural gas producing regions;
- worldwide and domestic economic conditions;
- the availability of transportation facilities;
- weather patterns; and
- actions of governmental authorities.

Competition for opportunities to replace and increase production and reserves is intense and could adversely affect the company.

Properties produce at a declining rate over time. In order to maintain its current production rates, the company must add new oil and natural gas reserves to replace those being depleted by production. Competition within the oil and natural gas industry is intense and many of the company's competitors have financial and other resources substantially greater than those available to the company. This could place the company at a disadvantage with respect to accessing opportunities to maintain, or increase, its oil and natural gas reserve base.

In the event that the company does not have adequate cash flow to fund operations, it may be required to use debt or equity financing.

The company makes, and will continue to make, significant expenditures to find, acquire, develop and produce oil and natural gas reserves. In the event of sustained low oil and gas prices, or if operating difficulties are encountered that result in cash flow from operations being less than expected, the company may have to reduce capital expenditures unless additional funds are raised through debt or equity financing. Debt or equity financing or cash generated by operations may not be available to the company in sufficient amounts or on acceptable terms to meet these requirements.

Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the company's success in locating and producing new reserves;
- the level of production from existing wells; and
- prices of oil and natural gas.

Issuing equity securities to satisfy the company's financing requirements could cause substantial dilution to existing stockholders. Debt financing could also make the company more vulnerable to competitive pressures and economic downturns.

In the event the company does not meet its plan for future Calliope installations, it may be required to record an impairment of the asset.

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.

The company believes that the number of future installations will be sufficient to demonstrate recoverability of the cost. Due to various factors, there have been no recent Calliope installations. If the Company is unable to achieve the expected level of installations, the company may in the future be required to record an impairment of the asset. Should this event occur, it would be a non-cash charge to income and would have no effect on working capital.

Reserve quantities and values are subject to many variables and estimates and actual results may vary.

This Annual Report on Form 10-K contains estimates of the company's proved oil and natural gas reserves and the estimated future net revenues from those reserves. Any significant negative variance in these estimates could have a material adverse effect on the company's future performance.

Reserve estimates are based on various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data.

Reserve estimates are dependent on many variables, and therefore, as more information becomes available, it is reasonable to expect that there will be changes to the estimates. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by the company. In addition, estimates of proved reserves will be adjusted in the future to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond the company's control.

As of October 31, 2010, approximately 29% of the company's estimated proved reserves are classified as proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is generally based on volumetric calculations rather than the performance data used to estimate reserves for producing properties. Recovery of proved undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Revenues from proved developed non-producing and proved undeveloped reserves will not be realized until sometime in the future. The reserve estimate includes an estimate of the capital expenditures required to develop these reserves as well as the timing of such expenditures. Although the company has prepared estimates of its proved undeveloped reserves and the associated development costs in accordance with industry standards, they are based on estimates, and actual results may vary from those estimates.

You should not interpret the present value of estimated reserves, or PV-10, as the current market value of reserves attributable to the company's properties. The 10% discount factor, which we are required to use to calculate PV-10 for reporting purposes, is not necessarily the most appropriate discount factor given actual interest rates and risks to which the company's business or the oil and natural gas industry in general are subject. The company is also required to base the PV-10 on average prices on the first day of each of the preceding twelve months and costs as of the date of the reserve estimate. Actual future prices and costs may be materially higher or lower. In addition to the price volatility factors discussed above, factors that will affect actual future net cash flows, include:

- the amount and timing of actual production;
- curtailments or increases in consumption by oil and natural gas purchasers; and
- changes in governmental regulations or taxation.

As a result, the company's actual future net cash flows could be materially different from the estimates included in this Annual Report on Form 10-K.

Full cost pool ceiling subject to reserve values.

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.

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".

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. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for more information related to ceiling test write-downs.

The company's reserve quantities and values are concentrated in a relative few properties and fields.

The company's reserves, and reserve values, are concentrated in 65 properties which represent 23% of the company's total properties but a disproportionate 80% of the discounted value (at 10%) of the company's reserves. Individual wells on which Calliope is installed comprise 15% of these significant properties and 15% of the discounted reserve value of such properties. Reserves added during 2010 comprise 9% of these significant properties and 6% of the discounted reserve value of such properties.

Estimates of reserve quantities and values for these 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, Calliope 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.

Competition for materials and services is intense and could adversely affect the company.

Major oil companies, independent producers, and institutional and individual investors are actively seeking oil and gas properties throughout the world, along with the equipment, labor and materials required to develop and operate properties. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. Many of the company's competitors have financial and technological resources which exceed those available to the company.

Natural gas derivatives involve credit risk and may limit future revenues from price increases.

To manage the company's exposure to price risks associated with the sale of oil and natural gas, the company periodically enters into derivative hedging transactions for a portion of its estimated production. These transactions may limit the company's potential gains if product prices were to rise substantially over the price established by the derivatives. In addition, such transactions may expose the company to the risk of financial loss in certain circumstances, including instances in which:

- the company's production is less than the amount hedged;
- the contractual counterparties fail to perform under the contracts; or
- a sudden, unexpected event materially impacts product prices.

The terms of the company's derivative agreements may also require that it furnish cash collateral, letters of credit or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations by the company to the counterparties, which would encumber the company's liquidity and capital resources.

The company’s natural gas derivatives are generally based on NYMEX prices but the company’s hedged natural gas production is primarily sold on a regional pipeline index price. The regional price is currently 5% below NYMEX prices. Regional weather conditions and other economic factors can frequently result in substantially higher basis differentials. Oil derivatives generally are in the form of costless collars.

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 its Balance Sheets and changes in fair value are recorded in the Statements of Operations as they occur.

The marketability of the company's natural gas production is dependent upon infrastructure, such as gathering systems, pipelines and processing facilities, that the company does not own or control.

The marketability of the company's natural gas production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities necessary to move the company's natural gas production to market. The company does not own this infrastructure and is dependent on other companies to provide it.

Oil and natural gas operations are inherently risky.

The oil and natural gas business involves a variety of risks, including the risks of operating hazards such as fires, explosions, cratering, blow-outs, and encountering formations with abnormal pressures. The occurrence of any of these risks could result in losses. The company maintains insurance against some, but not all, of these risks. The occurrence of a significant event that is not fully insured could have a material adverse effect on the company's financial position and results of operations.

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.

The company has recently expanded the volume and breadth of its exploration program with new drilling projects in North Dakota, Kansas, the Texas Panhandle and Nebraska. Compared to the company's conventional drilling, the Texas Panhandle and North Dakota horizontal drilling projects are substantially more expensive.

The company's operations are subject to a variety of regulatory constraints.

The production and sale of oil and natural gas are subject to a variety of federal, state and local government regulations. These include regulations relating to:

- the prevention of waste;
- the discharge of materials into the environment;
- the conservation of oil and natural gas;
- pollution;
- permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells; and
- the unitization and pooling of properties.

The company could incur liability for violations of these regulations. In addition, because current regulations covering the company's operations are subject to change at any time, the company could incur significant costs for future compliance.

Increases in taxes on energy sources may adversely affect the company's operations.

Federal, state and local governments which have jurisdiction in areas where the company operates impose taxes on the oil and natural gas products sold. Historically, there has been on-going consideration by federal, state and local officials concerning a variety of energy tax proposals. Such matters are beyond the company's ability to accurately predict or control.

ITEM 1B. UNRESOLVED STAFF COMMENTS

The company does not have any unresolved comments from the Commission.

ITEM 2. PROPERTIES

General

Refer to Item 1.—"Business Activities" for a general description of the company's oil and gas drilling and Calliope projects. Refer to Item 2. - "Significant Properties, Estimated Proved Oil and Gas Reserves, and Future Net Revenues" for information regarding the company's significant oil and gas properties.

The company owns approximately 70,000 gross acres primarily located on the northern shelf of the Anadarko Basin of Oklahoma, where it also owns interests in approximately 226 gross (71 net) wells, primarily natural gas wells. Historically, the company's drilling has been focused on this natural gas-prone area. Future drilling on the Oklahoma acreage is primarily dependent on natural gas prices, however, because much of the company's acreage is held by production, the timing of drilling is not critical in terms of preserving most of the company's acreage ownership.

In recent years, the company has significantly expanded both the volume and breadth of its drilling activities with new projects in North Dakota's Bakken, the Texas Panhandle, Kansas and Nebraska. Compared to conventional drilling, the North Dakota and Texas Panhandle horizontal drilling projects involve higher costs but significantly higher per well reserve potential. Conventional drilling in Kansas and Nebraska is less expensive than in Oklahoma. The company believes that all of the projects have excellent economic potential.

In Kansas and Nebraska, the company owns interests in approximately 147,000 gross acres (85,000 net) acres and it is continuing to expand its acreage position. At October 31, 2010, the company has participated in drilling 69 wells on its acreage, of which over 40% have been successfully completed as producers. The company is continuing to conduct an active drilling program expected to consist of two to three wells per month with working interests ranging from 12.5% to 95%. The company's Kansas and Nebraska drilling activities provide scientific diversification to the company's drilling program through the use of 3-D seismic to identify shallow oil prospects. The acreage is located in prolific oil producing areas where 3-D seismic has proven effective in identifying satellite structures near mature producing fields. Generally higher oil prices have justified using 3-D seismic technology to locate undrilled structures that are very difficult to find with old technology. Drilling targets the Lansing-Kansas City and Arbuckle formations at about 4,000 feet and, compared to the company's other projects, is relatively low cost, low risk, and exclusively targets oil reserves.

In 2009, the Kansas project yielded a significant oil discovery, known as Huslig Field, in which the company owns an 85% working interest. Huslig Field production peaked at 365 barrels of oil per day, net to Credo, which drove the 108% increase in 2009 oil production compared to 2008.

In North Dakota's Bakken oil resource play, the company has assembled approximately 8,000 gross (6,000 net) acres in the core of the play which are located primarily on the Fort Berthold Reservation, south and west of the Parshall Field. The acreage consists of approximately 50 initial well spacing units. The company expects that more than one well will be drilled on many spacing units. The project targets horizontal drilling for the Bakken and Sanish/Three Forks formations. Vertical well depths on the company's acreage are approximately 10,000 feet and the horizontal legs are generally expected to range between 5,000 and 10,000 feet. The company's interests range from very small to 56% depending on the size of the spacing unit.

To date, five wells have been drilled on the company's acreage. Three of the wells are producing and two are awaiting completion for production.

Several years ago, the U.S. Geological Survey estimated that the Bakken contains around 4.0 billion barrels of undiscovered oil. Since that time, reserve estimates for the play have been increasing steadily as technology improves. The North Dakota Department of Mineral Resources recently indicated that the North Dakota portion of the Bakken and Sanish/Three Forks plays could reasonably contain 11 billion barrels of recoverable oil.

The company anticipates drilling at least nine wells on its Bakken acreage during 2011.

In the Texas Panhandle, the company owns an average 33% working interest in about 3,000 gross acres located in Lipscomb and Hemphill counties. The company operates twelve vertical wells within the area and has recently drilled its first horizontal well which was completed in the Tonkawa formation. The 7,600-foot vertical well has an approximate 5,000-foot lateral and is expected to primarily produce oil. The area contains producing wells completed in the Morrow, Tonkawa and Cleveland formations.

The company owns the patents covering Calliope, together with the exclusive rights to the technology. The company has been instrumental in developing, testing, refining, and patenting the technology. Calliope efficiently lifts fluids from wellbores using pressure differentials, thus allowing gas previously trapped by fluid build-up in the wellbore to flow to the surface. Calliope is distinguished from all other fluid lift technologies because it does not rely on bottom-hole pressure and has only one down-hole moving part. Calliope is primarily applicable to mature natural gas wells in low pressure, natural gas expansion reservoirs at depths below 8,000 feet. The company has proven that Calliope will add 0.5 to 2.0 Bcf of proved gas reserves to many dead and uneconomic wells. The company believes there are presently many wells that meet its general criteria for Calliope candidate wells and thousands more that will meet the criteria in the future. The company has proven Calliope's economic viability and flexibility over a wide range of applications. External sources of capital have not been required for the development, refinement or installation of Calliope.

The company currently has Calliope installed on wells located in Oklahoma and Texas which include both sandstones and limestones in the Chester, Cotton Valley, Edwards, Hart, Hunton, Morrow, Nodosaria, Red Fork and Springer reservoirs. At the time Calliope was installed on 14 non-experimental wells, they were collectively at their economic limit and had no significant remaining reserves. Since Calliope was installed, the wells have produced 5.7 billion cubic feet of gas and they now have estimated ultimate (8/8ths) Calliope reserves totaling 12.1 billion cubic feet of gas. Nine of the Calliope wells are included in the company's Significant Properties.

Calliope's low per-unit finding and production cost have become increasingly attractive as the economics on many drilling projects have deteriorated due to lower product prices. The company also believes that lower natural gas prices may stimulate divestitures of marginal properties by other companies, including properties that have Calliope potential.

In November 2008, the company purchased all of the patents underlying Calliope, all related third party interests in future installations, and the patents covering a new fluid lift technology for shallow wells known as Tractor Seal for $4,500,000.

The company has three primary strategies to monetize its Calliope technology. The preferred strategy is to purchase dead and uneconomic wells from outside parties. A second strategy involves entering into joint ventures with outside parties that already own Calliope candidate wells. The third strategy is to drill new wells into old depleted fields and then use Calliope to recover the stranded gas. That strategy is highly dependent on natural gas prices and is generally not viable at current natural gas prices. The company is actively pursuing acquiring wells and joint ventures with other companies.

For additional information on the company's North Dakota Bakken and other drilling activities, see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations—Drilling Activities, on Page 27.

Significant Properties, Estimated Proved Oil and Gas Reserves, and Future Net Revenues

The company's reserves, and reserve values, are concentrated in 65 properties ("Significant Properties"). Some of the Significant Properties are individual wells and others are multi-well properties. At year-end, Significant Properties represent 23% of the company's total properties but a disproportionate 80% of the discounted value (at 10%) of the company's reserves. Individual Calliope wells comprise 15% of the Significant Properties and represent 15% of the discounted reserve value of such properties. Reserves added in 2010 comprise 9% of the Significant Properties and represent 6% of the discounted value of such properties.

The Securities and Exchange Commission ("SEC") adopted amendments designed to modernize the SEC oil and gas company reserves reporting requirements, effective for our company as of the quarter ended October 31, 2010. The most significant amendments to the requirements included the following:

- Commodity Prices-Economic producibility of reserves and discounted cash flows are now based on the average of the commodity spot price on the first day of each of the twelve preceding months unless contractual arrangements designate the price to be used.

- Disclosure of Unproved Reserves—Probable and possible reserves may be disclosed separately on a voluntary basis.

- Proved Undeveloped Reserve Guidelines—Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and the well from which the reserves are to be recovered is scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

- Reserves Estimation Using New Technologies—Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

- Reserves Personnel and Estimation Process—Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

- Non-Traditional Resources—The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective for our quarter and year ended October 31, 2010, as required by the SEC.

All of Credo's reserves are located within the continental United States. LaRoche Petroleum Engineers, LLC (LaRoche), our independent petroleum engineering consulting firm, prepared the company's estimated reserves as of October 31, 2010, 2009 and 2008. The company did not place any limitations on LaRoche in the conduct of determining their estimates of the company's reserves. We are not aware of any assumptions provided by management that were relied upon by LaRoche without testing.

Our year-end reserve report is prepared by LaRoche based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geosciences and engineering data, and other information we provide to them. This information is reviewed by knowledgeable members of our company to ensure accuracy and completeness of the data prior to submission to LaRoche. Upon analysis and evaluation of data provided, LaRoche issues a preliminary appraisal report of our reserves. The preliminary appraisal report and changes in our reserves are reviewed by our Engineering Manager and our President for completeness of the data presented and reasonableness of the results obtained. Once any questions have been addressed, LaRoche issues the final appraisal report, reflecting their conclusions.

Engineering Manager, Kenneth J. DeFehr, is a Registered Professional Engineer with 36 years of experience in the oil and gas industry. Mr. DeFehr received a Masters Degree in Civil Engineering from Texas A&M University in 1973, and began his petroleum engineering career with Phillips Petroleum from 1974 to 1982, where he worked in the Mid-Continent, Rockies, North Sea, and R&D. Mr. DeFehr served as Senior Petroleum Engineer for Axem Resources in Denver from 1982 to 1990, and has served as Engineering Manager for Credo Petroleum since 1990. During his career, Mr. DeFehr has been involved in exploration, property acquisitions, waterflooding, operations, and reserve evaluations.

A letter which identifies the professional qualifications of the individual at LaRoche who was responsible for overseeing the preparation of our reserve estimates as of October 31, 2010 has been filed as an addendum to Exhibit 99.1 to this report.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

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 (12) to the Consolidated Financial Statements where additional reserve information is provided. The average price used to calculate estimated future net revenues was $68.30, $69.24, and $62.25 per barrel of oil and $4.49, $4.49, and $3.50 per Mcf of gas as of October 31, 2010, 2009, and 2008, 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%
2010	**954,000**	**13,938,000**	**$ 69,865,000**	**$ 38,730,000**
2009	876,000	14,940,000	$ 71,863,000	$ 40,434,000
2008	710,000	15,525,000	$ 53,655,000	$ 32,330,000

* The percentage of total reserves classified as proved developed was approximately 71% in 2010, 61% in 2009, and 67% in 2008.

Oil reserves increased 9% and currently account for 29% of the company's total proved reserves. No gas wells were drilled in 2010 resulting in a 7% decline in gas reserves. The decline in gas reserves more than offset the 9% increase in oil reserves and resulted in a 3% decrease in total reserves, based on the industry standard six Mcf of gas to one barrel of oil conversion rate. Had the company not experienced completion timing delays on new wells in the North Dakota Bakken and Texas Panhandle, additional reserves would have been booked from those projects. Total reserves at October 31, 2010 were 3,277,000 barrels of oil equivalent, compared to 3,366,000 last year.

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. The following table provides a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note 12 to the company's Consolidated Financial Statements.

	Year Ended October 31,		
	2010	2009	2008
Estimated future net revenues discounted at 10%......................	$ 38,730,000	$ 40,434,000*	$ 32,330,000*
Future income tax expense	(14,898,000)	(15,119,000)	(9,119,000)
Effect of the 10% discount factor on future income tax expense	7,098,000	7,285,000	4,408,000
Standardized measure of discounted future net cash flows..................	$ 30,930,000	$ 32,600,000	$ 27,619,000

Production, Average Sales Prices and Average Production Costs

See Item 7 "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS" "Product Prices and Production"

Productive Wells and Developed Acreage

Developed acreage at October 31, 2010 totaled 22,000 net and 81,000 gross acres. At October 31, 2010, the company owned working interests in 74 net (305 gross) wells consisting of 52 net (224 gross) natural gas wells and 22 net (81 gross) oil wells. In addition, the company owned royalty and production payment interests in approximately 1,200 wells, primarily coal bed methane, located in Wyoming. In 2010, no wells were acquired, and 38 were sold or abandoned.

Undeveloped Acreage

The following table sets forth the number of undeveloped acres leased by the company (primarily located in the Mid-Continent and Rocky Mountain Regions) which will expire during the next five years (and thereafter) unless production is established in the interim. Undeveloped acres "held-by-production" represent the undeveloped portions of producing leases which will not expire until commercial production ceases.

Expiration Year Ending October 31,	Working Interest Acreage		Royalty Interest Acreage	
	Gross	Net	Gross	Net
2011	91,600	53,700	-	-
2012	23,000	14,300	-	-
2013	18,100	15,800	-	-
2014	6,300	4,600	-	-
2015	12,300	11,300	-	-
Thereafter	3,300	1,400	3,700	500
Held-By-Production	19,400	4,500	148,100	7,900
Total	174,000	105,600	151,800	8,400

In general "working interests" have operating rights and are burdened by costs of exploration or lease operations, while "royalty interests" are non-operated interests which are not burdened by such costs.

Drilling

The following tables set forth the number of gross and net oil and gas wells in which the company has participated and the results thereof for the periods indicated.

Gross Wells

Year Ended October 31,	Total Gross Wells	Exploratory			Development		
		Oil	Gas	Dry	Oil	Gas	Dry
2010 *	**34**	**15**	**4**	**15**	**-**	**-**	**-**
2009	25	7	2	12	1	2	1
2008	32	12	9	11	-	-	-

* Of the gross wells drilled in 2010, 1 of the oil wells, 1 of the gas wells and 3 of the dry holes were operated by the company. The remaining wells represent company participations in wells operated by others.

Net Wells

Year Ended October 31,	Total Net Wells	Exploratory			Development		
		Oil	Gas	Dry	Oil	Gas	Dry
2010*	**10.572**	**3.097**	**1.009**	**6.466**	**-**	**-**	**-**
2009	12.089	3.007	0.131	7.109	0.168	1.230	0.444
2008	6.581	1.874	1.886	2.821	-	-	-

* Of the net wells drilled in 2010, 0.500 of the oil wells, 0.840 gas wells and 2.342 dry holes were operated by the company. The remaining wells represent company participations in wells operated by others.

Insurance

The company believes that its existing insurance coverage is adequate to protect it from the risks associated with the ongoing operation of its business. This coverage includes commercial property, liability, limited equipment and auto, workers compensation, inland marine, directors and officers and excess liability.

Facilities and Employees

The company's corporate headquarters are located at 1801 Broadway, Suite 900, Denver, Colorado, in approximately 5,000 square feet occupied under a lease that expires in April 2011. Subsequent to October 31, 2010, the company extended its office space lease until April 2016.

As of October 31, 2010, the company had 14 employees. None of the company's employees is subject to a collective bargaining agreement, and the company considers relations with its employees to be good.

Company Website

Information related to the following items, among other information, can be found on the company's website at www.credopetroleum.com: (a) company filings with the Securities and Exchange Commission including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) of 15(d) of the Exchange Act as soon as reasonably practicable after filing, (b) company press releases, (c) officers, directors and ten percent shareholders filings on Forms 3, 4 and 5, and (d) the company's Code of Ethics and Audit Committee Charter. The company's website is not a part of, or incorporated by reference in, this Annual Report on Form 10-K.

ITEM 3. LEGAL PROCEEDINGS

From time to time, the company may be involved in litigation relating to claims arising out of the company's operations in the normal course of business. The company was named in a defendant in a lawsuit alleging breach of contract and other issues. The suit was settled on August 11, 2010 at a cost of $25,000 to Credo.

The company has been named as a defendant in a lawsuit brought by a former employee. The suit, Pownell v. Credo Petroleum Corp. et al., U.S.D.C. for the District of Colorado, alleges breach of contract and other employment issues. Although the company believes the allegations are without merit and that the company will ultimately prevail, the ultimate outcome of this lawsuit cannot be determined at this time.

ITEM 4. REMOVED AND RESERVED.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The company's common stock is traded on the NASDAQ Global Market[SM] under the symbol "CRED". Market quotations shown below were reported by the Financial Industry Regulatory Authority (FINRA) and represent prices between dealers excluding retail mark-up or commissions and may not necessarily represent actual transactions.

	2010		2009	
Quarter Ended	High	Low	High	Low
January 31	$ 10.52	$ 8.70	$ 10.21	$ 7.86
April 30	$ 10.47	$ 8.40	$ 9.53	$ 6.73
July 31	$ 9.91	$ 7.13	$ 12.87	$ 8.08
October 31	$ 8.63	$ 7.67	$ 12.90	$ 9.72

At January 4, 2011, the company had 2,239 shareholders of record. The company has never paid a cash dividend and does not expect to pay any cash dividends in the foreseeable future. Earnings are reinvested in business activities.

Issuer Purchases of Equity Securities.

During fiscal year 2010, the company repurchased 231,995 shares of its common stock on the open market at a weighted average price of $8.91. The purchases were made pursuant to a stock repurchase plan announced on September 24, 2008 and extended by the Board of Directors on April 9, 2009 and July 29, 2010. The extended plan authorized repurchases up to $5,000,000, but could be expanded, suspended or discontinued at any time. At October 31, 2010, the company has repurchased 527,429 shares of common stock at an average price per share of $8.74. Subsequent to

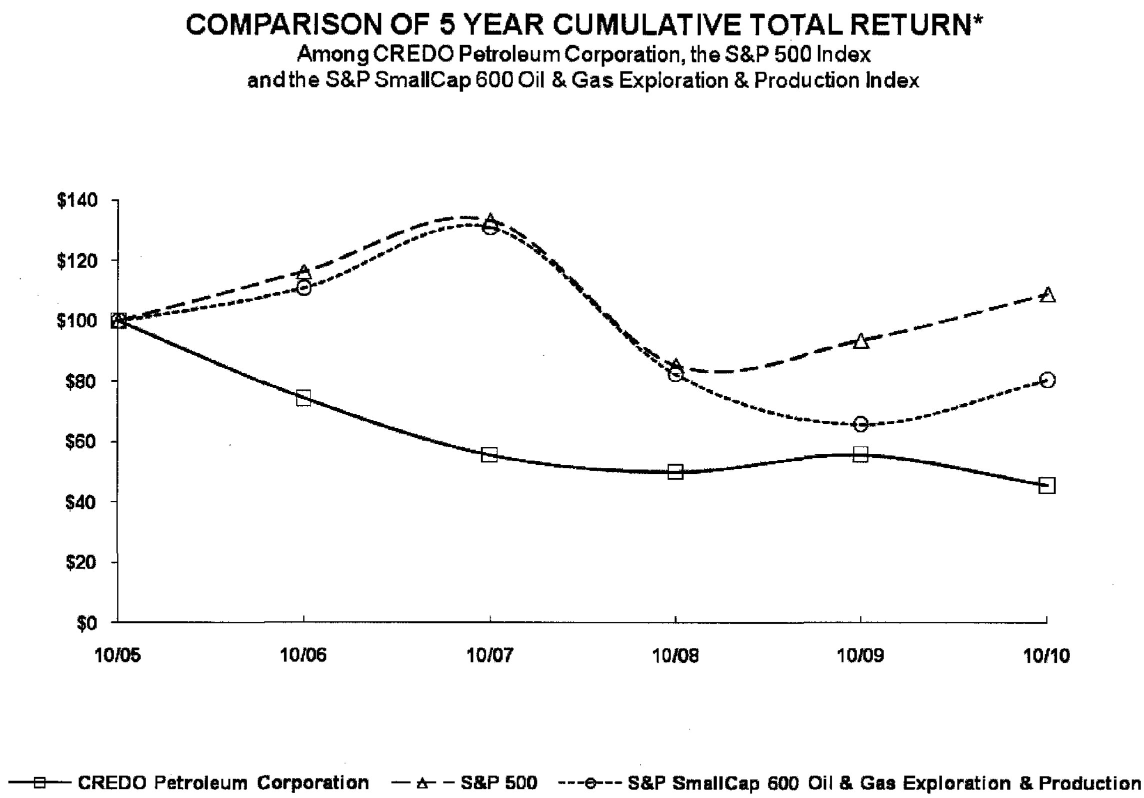
October 31, 2010, and through January 13, 2011, the company has repurchased 18,000 shares, bringing the total shares repurchased to 545,429 at an average price per share of $8.72.

Issuer Purchases of Equity Securities

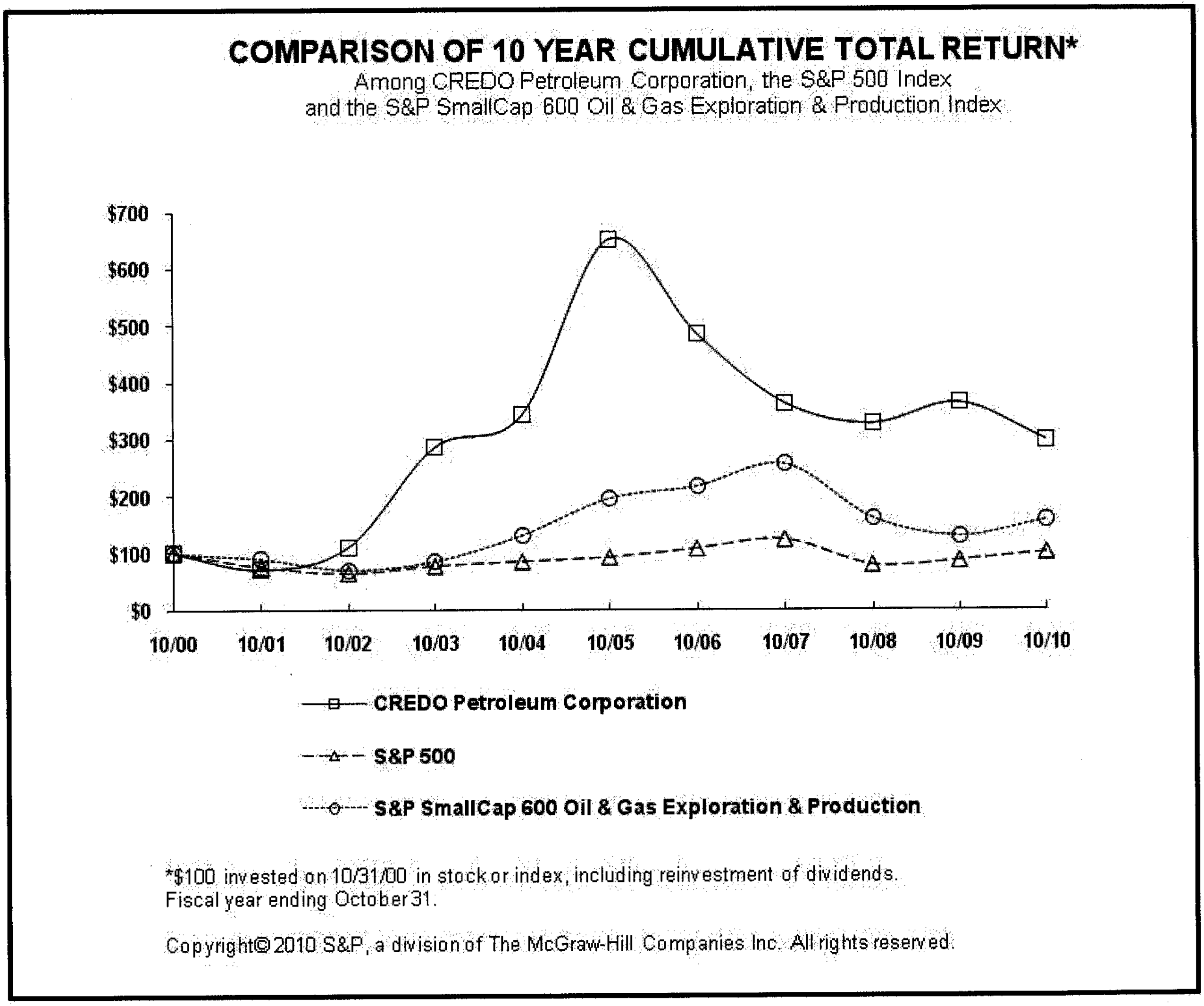
Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plan	Maximum dollar value of shares that may yet be purchased under the plan
September 22, 2008 - October 31, 2008	98,940	$ 7.31	98,940	$ 1,277,000
November 1 - 30 2008	45,954	$ 9.45	45,954	$ 843,000
December 1 - 31 2008	22,350	$ 8.88	22,350	$ 645,000
January 1 - 31 2009	6,182	$ 9.16	6,182	$ 588,000
February 1 - 28, 2009 ...	29,104	$ 8.56	29,104	$ 338,000
March 1 - 31, 2009	15,110	$ 7.49	15,110	$ 225,000
April 1 - 30, 2009	12,800	$ 7.76	12,800	$ 2,126,000
June 1 - 30, 2009	1,031	$ 9.58	1,031	$ 2,116,000
July 1 - 31, 2009	6,451	$ 10.90	6,451	$ 2,045,000
August 1-31, 2009	-	$ -	-	$ 2,045,000
September 1-30, 2009	25,412	$ 10.32	25,412	$ 1,783,000
October 1-31, 2009	32,100	$ 10.19	32,100	$ 1,456,000
November 1 - 30, 2009 .	40,937	$ 10.19	40,937	$ 1,039,000
December 1 - 31, 2009 .	-	$ -	-	$ 1,039,000
January 1 - 31, 2010 ..	26,520	$ 9.38	26,520	$ 790,000
February 1 - 28, 2010 .	23,800	$ 8.87	23,800	$ 579,000
March 1-31, 2010	7,800	$ 9.73	7,800	$ 503,000
April 1 - 30, 2010	16,378	$ 9.84	16,378	$ 342,000
May 1 - 30, 2010	18,600	$ 9.24	18,600	$ 170,000
June 1 - 30, 2010	21,167	$ 8.02	21,167	$ -
July 1 - 31, 2010	24,000	$ 7.59	24,000	$ 818,000
August 1 - 31, 2010	13,827	$ 7.87	13,827	$ 709,000
September 1 - 30, 2010 ..	26,566	$ 8.25	26,566	$ 490,000
October 1 - 31, 2010	12,400	$ 8.07	12,400	$ 390,000
Total	527,429	$ 8.72	527,429	$ 390,000

Performance Graph

The following performance graph compares the cumulative total stockholder return on the company's common stock for the five-year period ended October 31, 2010 with the cumulative total return of Standard and Poor's SmallCap 600 Oil and Gas Exploration and Production and the Standard & Poor's 500 Stock Index. The identities of the companies included in the index will be provided upon request.



*$100 invested on 10/31/05 in stock or index, including reinvestment of dividends.
Fiscal year ending October 31.



The information in this Annual Report on Form 10-K appearing under the heading "Stock Performance Graph" is being furnished pursuant to Item 201(e) of Regulation S-K and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth certain financial information with respect to the company and is qualified in its entirety by reference to the historical financial statements and notes thereto of the company included in Item 8, "Financial Statements and Supplementary Data." The statement of operations and balance sheet data included in this table for each of the five years in the period ended October 31, 2010 were derived from the audited financial statements and the accompanying notes to those financial statements.

	Years Ended October 31,				
	2010	2009	2008	2007	2006
Audited Financial Information					
Statement of Operations Data:					
Oil and gas sales	**$ 11,566,000**	$ 10,067,000	$ 17,345,000	$14,265,000	$16,103,000
Oil and gas production expense	**3,192,000**	3,260,000	3,861,000	3,375,000	3,407,000
Depreciation, depletion and amortization	**3,602,000**	4,439,000	3,583,000	3,666,000	3,642,000
Non-cash writedown of oil & gas properties and impairment of long lived assets......	**-**	24,653,000	-	-	-
General and administrative .	**2,107,000**	3,250,000	1,637,000	1,397,000	1,291,000
Income(loss) from operations	**2,665,000**	(25,535,000)	8,264,000	5,827,000	7,763,000
Realized and Unrealized gains(losses) from derivative contracts......	**42,000**	2,079,000	188,000	1,455,000	1,061,000
Income(loss) before income taxes	**2,815,000**	(23,515,000)	8,153,000	8,075,000	9,436,000
Net income(loss)	**2,203,000**	(14,454,000)	5,993,000	5,760,000	6,836,000
Earnings(loss) per share:					
Basic.....................	**$ 0.22**	$ (1.40)	$ 0.62	$ 0.62	$ 0.74
Diluted..................	**$ 0.22**	$ (1.40)	$ 0.61	$ 0.61	$ 0.72
Weighted-average shares outstanding[1]:					
Basic....................	**10,183,000**	10,326,000	9,697,000	9,280,000	9,207,000
Diluted..................	**10,202,000**	10,326,000	9,758,000	9,395,000	9,482,000
Balance Sheet Data:					
Working capital	**9,661,000**	13,542,000	24,160,000	12,511,000	10,073,000
Total assets	**53,405,000**	52,552,000	80,650,000	55,349,000	47,759,000
Long-term obligations:					
Deferred income taxes-net.	**3,281,000**	2,537,000	11,117,000	9,204,000	8,039,000
Asset retirement obligation	**1,132,000**	1,502,000	1,338,000	1,016,000	954,000
Exclusive license agreement obligation	**-**	-	-	85,000	163,000
Stockholders' equity	**46,567,000**	46,056,000	62,211,000	41,140,000	34,767,000
Unaudited Operating Data					
Production Volumes:					
Oil (Bbls)	**97,000**	116,000	56,000	51,000	41,000
Gas (Mcf)	**1,038,000**	1,229,000	1,545,000	1,926,000	2,176,000
BOE......................	**270,000**	321,000	314,000	372,000	404,000
Avg. sales price before realized derivative gains & losses:					
Per Bbls	**$ 70.88**	$ 51.46	$ 99.28	$ 60.95	$ 61.14
Per Mcf	**$ 4.54**	$ 3.35	$ 7.65	$ 5.79	$ 6.24
Reserves[(1)]					
Oil (Bbls)	**954,000**	876,000	710,000	591,000	422,000
Gas (Mcf)	**13,938,000**	14,940,000	15,525,000	16,973,000	16,005,000
BOE......................	**3,277,000**	3,366,000	3,297,000	3,420,000	3,090,000
Estimated future net revenues	**$ 69,865,000**	$ 71,863,000	$ 53,655,000	$101,501,000	$84,861,000
Estimated future net revenues discounted at 10%	**$ 38,730,000**	$ 40,434,000	$ 32,330,000	$62,071,000	$52,328,000

(1) See Footnote 12 to the Consolidated Financial Statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Operations

Summary -- During 2009 and 2010 the company's operations focused on oil drilling in central and western Kansas and in the North Dakota Bakken oil resource play. In 2011 the company will expand its drilling operations into southwestern Nebraska and into oil-rich zones in the Texas Panhandle such as the Tonkawa and Cleveland. These zones have become prime horizontal drilling targets.

These activities are discussed in greater detail below.

The company believes that its geographically diverse drilling projects provide an excellent balance for achieving its goal of adding long-lived oil and natural gas reserves and production at reasonable costs and risks. However, it should be expected that successful results will occur unevenly for each of the drilling projects. Drilling economics are dependent on both the timing of drilling and on the drilling success rate.

The company will continue to actively pursue adding reserves through its drilling projects in fiscal 2011, 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, fracture stimulation equipment and related services, as well as access to wells for application of the company's Calliope Gas Recovery System. The prevailing price of oil and natural gas has a significant effect on demand and, thus, the related cost of such services and wells.

Results of Operations

In 2010, oil and gas revenues increased 15% to $11,566,000 compared to $10,067,000 in 2009. The increase was due to a 38% increase in oil prices and a 37% increase in natural gas prices. As the oil and gas price/volume table on page 25 shows, oil prices increased to $70.88 per barrel and natural gas sales prices increased to $4.54 per Mcf. The net effect of these price changes was to increase total oil and gas sales by $3,710,000. Realized derivative gains were $115,000 in 2010 compared to $3,720,000 in 2009. Unrealized derivative losses were $73,000 in 2010 compared to unrealized losses of $1,641,000 in 2009. During the same period, the company's total production decreased 16% to 270,000 BOE, resulting in a decrease in oil and gas sales of $2,211,000. The decline in 2010 oil production resulted because of delays caused by shortages of fracture stimulation equipment for horizontal wells in the North Dakota Bakken and the Texas Panhandle. The situation was exacerbated by the expected flush production decline on the Huslig Field discovery which peaked last year at about 365 barrels of oil per day, net to Credo. In addition, the company did not drill any gas wells during 2010 due to low natural gas prices. Investment and other income increased primarily due to the impact of market place improvements on the company's investments.

In 2010, total costs and expenses, excluding the impairment loss of $24,653,000 in 2009, decreased 19% to $8,901,000 compared to $10,949,000 in 2009. Oil and gas production expenses decreased 2% due primarily to decreased field level service costs. General and administrative expenses decreased $1,143,000 to $2,107,000 primarily due to decreased salaries and benefits and lower legal and professional fees.

The effective income tax rate was 22% and 38.5% for the 2010 and 2009 periods, respectively. The variation from the statutory rate in 2010 is primarily due to percentage depletion.

In 2009, oil and gas revenues decreased 42% to $10,067,000 compared to $17,345,000 in 2008. The decrease was due to a 48% decrease in oil prices and a 56% decrease in natural gas prices. As the oil and gas price/volume table on page 24 shows, oil prices decreased to $51.46 per barrel and total natural gas prices decreased to $3.35 per Mcf. The net effect of these price realization changes was to decrease total oil and gas sales by $9,305,000. Realized derivative gains were $3,720,000 in 2009 compared to losses of $1,113,000 in 2008. During the same period, the company's oil production increased 108% to 116,000 barrels, which offset a 21% reduction in gas production to 1,229,000 Mcf resulting in an increase in oil and gas sales of $2,028,000. Unrealized derivative losses were $1,641,000 in 2009 compared to unrealized gains of $1,301,000 in 2008. Investment and other income decreased primarily due to the impact of market place declines on the company's investments coupled with a liquidation of investments during 2009.

In 2009, total costs and expenses, excluding oil and gas property and intangible asset impairment charges, increased 21% to $10,949,000 compared to $9,081,000 in 2008. Oil and gas production expenses decreased 16% due primarily to decreased field level service costs. General and administrative expenses increased $1,613,000 to $3,250,000 primarily due to increases in salaries and benefits, Board of Director fees and expenses, legal fees and a one-time $414,000 retirement payment to the Chief Executive Officer in lieu of a $2,500 per month retirement annuity.

Due primarily to low natural gas prices during the first half of 2009, for the fiscal year ended October 31, 2009, the company recorded non-cash ceiling test write-downs at the end of the first and second quarters, in the aggregate of $23,726,000. The company also recorded intangible asset impairment charges of $927,000 in the first quarter of 2009.

Liquidity and Capital Resources

At October 31, 2010, working capital decreased to $9,661,000, compared to $13,542,000 at October 31, 2009, primarily due to capital expenditures for oil and gas activities. For the year-ended October 31, 2010, net cash provided by operating activities was $4,533,000 compared to $9,932,000 for the same period in 2009. The difference is primarily due to the sale of $2,229,000 of short term investments in 2009 and the purchase of $1,500,000 in short term investments in 2010. During 2009 and 2010, the company liquidated the majority of its short term investments in professionally managed limited partnerships. Other short term investments are directly invested in certificates of deposit and mutual funds. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $8,671,000 and $11,480,000 in 2010 and 2009, respectively. Financing activities primarily included the purchase of treasury stock of $2,066,000 and $1,821,000 in 2010 and 2009

The company's earnings before interest, taxes, depreciation, depletion and amortization and write-downs of oil and gas properties and impairment losses ("EBITDA") was $6,417,000 for the year ended October 31, 2010 and $5,580,000 for the prior year. 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:

	For The Year Ended October 31,		
	2010	2009	2008
RECONCILIATION OF EBITDA:			
Net Income (Loss)	**$ 2,203,000**	$ (14,454,000)	$ 5,993,000
Add Back(Deduct):			
Interest Expense	**-**	3,000	8,000
Income Tax Expense (Benefit)	**612,000**	(9,061,000)	2,160,000
Depreciation, Depletion and Amortization Expense	**3,602,000**	4,439,000	3,583,000
Write-Down of oil and natural gas properties and impairment of intangible assets	**-**	24,653,000	-
EBITDA	**$ 6,417,000**	$ 5,580,000	$ 11,744,000

Existing working capital and anticipated cash flow are expected to be sufficient to fund operations and capital requirements for at least the next 12 months. At October 31, 2010, the company had no lines of credit or other bank financing arrangements except for the derivative line of credit discussed in Note 5 to the Consolidated Financial Statements. 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.

As of October 31, 2010, the company had the following known contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Operating lease obligations	20,000	20,000	-	-	-
Total	$ 20,000	$ 20,000	$ -	$ -	$ -

Off-Balance Sheet Arrangements

The company has no off-balance sheet arrangements at October 31, 2010.

Product Prices and Production

Refer to Item 1., "Markets and Customers", for discussion of oil and gas prices and marketing.

Oil and natural gas sales volume and price realization comparisons for the years ended October 31, 2010, 2009 and 2008 are set forth below. Prices shown are market price and do not include realized hedging gains and losses.

	Twelve Months Ended October 31,					
	2010 Wellhead		2009 Wellhead		2008 Wellhead	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Oil (bbls)	**96,700**	**$ 70.88**	115,700	$ 51.46	56,000	$ 99.28
Gas (Mcf)	**1,038,000**	**$ 4.54**	1,229,000	$ 3.35	1,545,000	$ 7.65
BOE (Barrels of Oil Equivalent) .	**269,700**	**$ 42.89**	320,500	$ 31.41	313,500	$ 55.33

The decline in 2010 oil production resulted because of delays caused by shortages of fracture stimulation equipment for horizontal wells in the North Dakota Bakken and the Texas Panhandle. The situation was exacerbated by the expected flush production decline on the Huslig Field discovery which peaked last year at about 365 barrels of oil per day, net to Credo. The flush production from the Huslig Field drove a 108% increase in 2009 oil production over 2008 levels. The expected decline in flush production from the Huslig Field contributed to a 7% decrease in oil production this year. The company did not drill any gas wells in 2010 due to low natural gas prices, resulting in lower gas production in 2010.

The effect of realized derivative gains and losses and market prices on total price realizations are reflected in the following table:

	Twelve Months Ended October 31,								
	2010			2009			2008		
Product	**Net Wellhead Price**	**Realized Derivative Gain**	**Effective Price Realization**	Net Wellhead Price	Realized Derivative Gain	Effective Price Realization	Net Wellhead Price	Realized Derivative Gain	Effective Price Realization
Oil ...	**$ 70.88**	**$ -**	**$ 70.88**	$ 51.46	$ -	$ 51.46	$ 99.28	$ -	$ 99.28
Gas ...	**$ 4.54**	**$ 0.11**	**$ 4.65**	$ 3.35	$ 3.02	$ 6.37	$ 7.65	$ (0.25)	$ 7.40

Average production costs, including production taxes, per equivalent BOE of production (using the industry standard of six Mcf of gas to one barrel of oil conversion ration) were $11.84, $10.17 and $12.32 per BOE in 2010, 2009 and 2008 respectively. Depreciation, depletion and amortization per equivalent BOE for the same periods were $11.60, $12.27 and $10.99.

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 production when the potential for significant downward price movement is anticipated. These transactions typically take the form of costless collars for oil and forward short positions based upon the NYMEX futures market for natural gas, and are closed by purchasing offsetting positions. Such contracts do not exceed estimated production volumes and are authorized by the company's Board of Directors. 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.

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 its Balance Sheet and changes in fair value are recorded in the Consolidated Statements of Operations as they occur.

At October 31, 2010 the company held open derivative contracts representing natural gas short sales positions for 40,000 MMBtus at NYMEX basis prices ranging from $6.91 to $7.27 and covering the production months of November and December 2010. The company closed the hedge transaction by purchasing offsetting contracts at NYMEX basis prices of $5.83. These positions are presented net and represent an unrealized gain of $50,000 at October 31, 2010 which was realized as income subsequent to year-end. Average natural gas prices received in the company's primary market have historically been 15%-17% below NYMEX prices due to basis differentials compared to the current differentials of about 5%.

At October 31, 2010 the company also held natural gas basis differential hedges on 80,000 MMBtus with NYMEX vs. Panhandle Eastern Pipeline basis differentials of $0.47 and covering the production months of November and December 2010. These open basis differential contracts represent unrealized losses of $19,000 at October 31, 2010.

Subsequent to October 31, 2010, the company entered into natural gas derivative contracts for 30,000 MBTU's for each of production months of January, February and March 2011. These contracts are at NYMEX Basis prices of $4.35-4.52 per Mcf.

The company entered into costless collar derivative contracts subsequent to year-end for 5,000 barrels of oil for each production month of calendar year 2011 with a floor of $80.00 and a ceiling ranging from $90.50 to 95.00 per barrel and for 3,000 barrels of oil for each production month of calendar year 2012 with a floor of $80.00 and a ceiling ranging from $94.00 to $99.00 per barrel.

The company has a derivative 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 available is $7,200,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the company's bank, and prohibits funded debt in excess of $500,000. The line expires May 1, 2013.

Oil and Gas Activities

Capital Spending. Capital spending in 2010 totaled $8,703,000, consisting of additions to oil and gas properties. In November, 2008, the company purchased the Calliope patents and the remaining third party rights in the Calliope technology. In addition, the company purchased the patents for its new Tractor Seal fluid lift technology together with all third party rights in the technology. The Tractor Seal technology is currently in the development stage and, except for the patents, the company has not yet provided public disclosure regarding the technology. The total purchase price was $4,500,000.

Drilling Activities

The company owns approximately 70,000 gross acres primarily located on the northern shelf of the Anadarko Basin of Oklahoma where it also owns interests in approximately 226 gross (71 net) wells, primarily natural gas wells. Historically, the company's drilling has been focused on this natural gas-prone area. However, no gas wells were drilled in Oklahoma during 2010 due to low gas prices. Future drilling on the Oklahoma acreage is primarily dependent on natural gas prices, however, because much of the company's acreage is held by production, the timing of drilling is not critical in terms of preserving most of the company's acreage ownership.

In recent years, the company has significantly expanded both the volume and breadth of its drilling activities with new projects in Kansas, Nebraska, North Dakota's Bakken Play, and the Texas Panhandle. Compared to drilling in Oklahoma, the North Dakota and Texas Panhandle horizontal drilling projects involve higher costs but significantly higher per well reserve potential. Conventional drilling in Kansas and Nebraska is less expensive than in Oklahoma.

In Kansas and Nebraska, the company owns interests in approximately 147,000 gross acres and 85,000 net acres and it is continuing to expand its acreage position. At October 31, 2010, the company has participated in drilling 69 wells on its acreage, of which over 40% have been successfully completed as producers. The company is continuing to conduct an active drilling program expected to consist of two to three wells per month with working interests ranging from 12.5% to 95%. The company's Kansas and Nebraska drilling activities provide scientific diversification to the company's drilling program through the use of 3-D seismic to identify shallow oil prospects.

In 2009, the Kansas project yielded a significant oil discovery, known as Huslig Field, in which the company owns an 85% working interest. Huslig Field production peaked at 365 barrels of oil per day, net to Credo, which drove the 108% increase in 2009 oil production compared to 2008.

In North Dakota's Bakken oil resource play, the company has assembled approximately 8,000 gross (6,000 net) acres in the core of the play which are located primarily on the Fort Berthold Reservation, south and west of the Parshall Field. The acreage consists of approximately 50 initial well spacing units. The company expects that more than one well will be drilled on many spacing units. The project targets horizontal drilling for the Bakken and Sanish/Three Forks formations. Vertical well depths on the company's acreage are approximately 10,000 feet and the horizontal legs are generally expected to range between 5,000 and 10,000 feet. The company's interests range from very small to 56% depending on the size of the spacing unit.

To date, five wells have been drilled on the company's acreage. Three of the wells are producing and two are awaiting completion for production.

The company's third high rate Bakken producer was recently completed. The Petro-Hunt 3-A well was drilled on a 1,280-acre spacing unit with an approximate 10,000-foot lateral, and was fracture stimulated in 25 stages. The well flowed at a restricted rate of 1,367 barrels of oil equivalent during a 24-hour test on a small (18/64") choke with flowing casing pressure of 3,050 psi. While the well was drilled in fiscal 2010, the completion phase was delayed until recently due to shortages of fracture stimulation equipment. The well is located in Dunn County on the Fort Berthold Reservation about four miles southeast of the company's Petro-Hunt 17-D well. Credo owns an 18.75% working interest in the new well.

The company's first Bakken well (Petro-Hunt 17-D) tested at an initial rate of 1,474 barrels of oil equivalent per day ("BOEPD") on a 20/64" choke, and has produced about 87,000 BOE in 11 months. The well is also located in Dunn County on the southwest portion of the Fort Berthold Reservation, and appears to be one of the best wells in the area. Credo owns a 10% working interest in the well.

The company's second Bakken well (Brigham Weisz 11-14) tested at an initial rate of 2,278 BOEPD on a 48/64" choke, and has produced approximately 52,000 BOE in four months. The well is located about 50 miles northwest of the Petro-Hunt 17-D in Williams County. Credo owns a 6.25% working interest in the well. Brigham's development plans for the spacing unit could potentially include two additional Bakken wells and up to three Sanish/Three Forks wells.

Drilling is complete on two additional wells located on the Fort Berthold Reservation where Credo owns small interests – the Zenergy 14-23 well and the Questar MHA 1-32 well. Both wells are currently awaiting completion for production. Credo owns 1.56% and 3.57% in the wells, respectively.

The company anticipates drilling at least nine wells on its Bakken acreage during 2011.

In the Texas Panhandle, the company owns an average 33% working interest in about 3,000 gross acres. The company has recently drilled its first horizontal well. The 7,600-foot vertical depth well has an approximate 5,000-foot horizontal lateral and is expected to primarily produce oil. Credo owns a 22% working interest in the well with Chesapeake Energy Corporation, the nation's most active driller, as the Operator. Drilling and high pressure fracturing have been completed, a pumping unit has been installed, and fracture fluids are currently being recovered.

Reserves. Refer to Item 2, "Properties, Significant Properties, Estimated Proved Oil and Gas Reserves and Future Net Revenues", for information regarding oil and gas reserves.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires the company 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. 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 natural gas reserves, and the estimate of its asset retirement obligations.

Derivatives. 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 its balance sheet and changes in fair value are recorded in the Consolidated Statements of Operations as they occur.

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. 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.

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 the average prices in effect as of the first day of each month 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 average prices and costs in effect during the preceding year.

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 are often different than the estimated costs.

Estimates of reserve quantities and values for certain 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 Calliope System is generally installed on mature wells. As such, they contain older down-hole equipment, such as casing, that is more subject to failure than new equipment. The failure of such equipment can result in complete loss of a well. Historically, performance of the company's wells has not caused significant revisions in its proved reserves.

One measure of the life of the company's proved reserves can be calculated by dividing proved reserves at fiscal year end 2010 by production for fiscal year 2010. This measure yields an average reserve life of 12.1 years. 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.

In December 2008, the Securities and Exchange Commission ("SEC") adopted revisions to its oil and gas disclosure requirements that are intended to align them with current practices and changes in technology. Among other things, the amendments: replace the single-day fiscal period-end pricing assumption with a twelve-month average pricing assumption; permit the disclosure of probable and possible reserves; allow the use of certain technologies to establish reserves; require the disclosure of the qualifications of the technical person primarily responsible for preparing the reserves estimates or conducting a reserves audit; require the filing of the independent reserve engineers' summary report; and permit the disclosure of a reserves sensitivity analysis table to illustrate the impact of different price and/or cost assumptions on reserves. These amendments are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009 (fiscal year 2010 for the company) with early adoption prohibited. The company adopted the revisions and amendments effective with this report on Form 10-K. Adoption of the New Rules did not have a significant impact on the Company's reserve quantities.

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 to assure that the remaining value is recoverable.

The company believes that the number of future installations will be sufficient to demonstrate recoverability of the cost. Due to various factors, there have been no recent Calliope installations. If the Company is unable to achieve the expected level of installations, the company may in the future be required to record an impairment of the asset. Should this event occur, it would be a non-cash charge to income and would have no effect on working capital.

Asset Retirement Obligations. The FASB authoritative guidance 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, 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.

ITEM 7A. 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 . These transactions typically take the form of costless collars for oil and forward short positions based upon the NYMEX futures market for natural gas, and are closed by purchasing offsetting positions. Such contracts do not exceed estimated production volumes and are authorized by the company's Board of Directors. 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 October 31, 2010 the company held open derivative contracts representing natural gas short sales positions for 40,000 MMBtus at NYMEX basis prices ranging from $6.91 to $7.27 and covering the production months of November 2010 through December 2010. The company also held open offsetting derivative contracts with the same counterparty for 40,000 MMBtus at NYMEX basis prices of $5.83 and covering the production months of November 2010 through December 2010. These positions are presented net due to the contractual netting provisions with the counterparty. The open derivative contracts net to an unrealized gain of $50,000 at October 31, 2010. Average natural gas prices received in the company's primary market have historically been 15% - 17% below NYMEX prices due to basis differentials compared to the current differentials of about 5%.

At October 31, 2010 the company also held natural gas basis differential hedges on 80,000 MMBtus with NYMEX vs. Panhandle Eastern Pipeline basis differentials of $0.47 and covering the production months of November 2010 through December 2010. These open basis differential contracts represent unrealized losses of $19,000 at October 31, 2010.

Subsequent to October 31, the November and December natural gas related derivative contracts closed, resulting in net realized derivative gains of $30,000. Subsequent to October 31, 2010, the company also entered into natural gas derivative contracts for 30,000 MBTU's for each of production months of January, February and March 2011. These contracts are at NYMEX Basis prices of $4.35-4.52 per Mcf.

Also subsequent to October 31, 2010 the company entered into costless collar derivative contracts for 5,000 barrels of oil for each production month of calendar year 2011 with a floor of $80.00 and a ceiling ranging from $90.50 to $97.50 per barrel. The company also entered into costless collar derivative contracts for 3,000 barrels of oil for each production month of calendar year 2012 with a floor of $80.00 and a ceiling ranging from $94.00 to $99.00 per barrel.

The company has a derivative 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 available is

$7,200,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the company's bank, and prohibits funded debt in excess of $500,000. The line expires May 1, 2013.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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CONSOLIDATED BALANCE SHEETS
October 31, 2010 and 2009

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

ASSETS	2010	2009
Current assets:		
Cash and cash equivalents	$ 7,179,000	$ 12,348,000
Short-term investments	1,990,000	635,000
Receivables:		
Trade	479,000	487,000
Accrued oil and gas sales	1,574,000	1,566,000
Derivative assets	32,000	104,000
Other current assets	832,000	859,000
Total current assets	12,086,000	15,999,000
Long-term assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	8,801,000	7,363,000
Evaluated oil and gas properties	83,360,000	76,127,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	(56,339,000)	(53,211,000)
Net oil and gas properties	35,822,000	30,279,000
Intangible assets, net of accumulated amortization of $872,000 in 2010 and $436,000 in 2009	3,578,000	4,013,000
Compressor and tubular inventory to be used in development of oil and gas properties	1,855,000	1,865,000
Other, net	64,000	396,000
Total assets	$ 53,405,000	$ 52,552,000
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,200,000	$ 407,000
Revenue distribution payable	565,000	653,000
Accrued compensation	466,000	948,000
Other accrued liabilities	177,000	394,000
Income taxes payable	17,000	55,000
Total current liabilities	2,425,000	2,457,000
Long-term liabilities:		
Deferred income taxes, net	3,281,000	2,537,000
Asset retirement obligation	1,132,000	1,502,000
Total liabilities	6,838,000	6,496,000
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 shares issued	1,066,000	1,066,000
Capital in excess of par value	31,486,000	31,472,000
Treasury stock, at cost, 601,000 shares in 2010, and 419,000 shares in 2009	(4,509,000)	(2,803,000)
Retained earnings	18,524,000	16,321,000
Total stockholders' equity	46,567,000	46,056,000
Total liabilities and stockholders' equity	$ 53,405,000	$ 52,552,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three Years Ended October 31, 2010

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2010	2009	2008
Oil sales	$ 6,855,000	$ 5,953,000	$ 5,530,000
Gas sales	4,711,000	4,114,000	11,815,000
	11,566,000	10,067,000	17,345,000
Costs and expenses:			
Oil and gas production	3,192,000	3,260,000	3,861,000
Depreciation, depletion and amortization	3,602,000	4,439,000	3,583,000
Write-down of oil and natural gas properties (Note 3) and impairment of long lived assets (Note 8)	-	24,653,000	-
General and administrative	2,107,000	3,250,000	1,637,000
	8,901,000	35,602,000	9,081,000
Income(loss) from operations	2,665,000	(25,535,000)	8,264,000
Other income and (expense)			
Realized and Unrealized gains (losses) from derivative contracts	42,000	2,079,000	188,000
Investment and other income (loss)	108,000	(59,000)	(299,000)
	150,000	2,020,000	(111,000)
Income(loss) before income taxes	2,815,000)	(23,515,000)	8,153,000
Income taxes	(612,000)	9,061,000	(2,160,000)
Net income(loss)	$ 2,203,000	$(14,454,000)	$ 5,993,000
Earnings(loss) per share of Common Stock-Basic	$ 0.22	$ (1.40)	$ .62
Earnings(loss) per share of Common Stock-Diluted	$ 0.22	$ (1.40)	$ .61
Weighted average number of shares of common stock and dilutive securities:			
Basic	10,183,000	10,326,000	9,697,000
Diluted	10,202,000	10,326,000	9,758,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Three Years Ended October 31, 2010

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	Common Stock		Capital In Excess Of Par Value	Treasury Stock	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
Balance, October 31, 2007	9,510,000	$951,000	$15,913,000	$(506,000)	$24,782,000	$41,140,000
Comprehensive income (loss):						
Net income	-	-	-	-	5,993,000	5,993,000
Sale of common stock	1,150,000	115,000	16,560,000	-	-	16,675,000
Payment of transactions costs	-	-	(1,580,000)	-	-	(1,580,000)
Purchase of treasury stock	-	-	-	(722,000)	-	(722,000)
Exercise of common stock options	-	-	294,000	246,000	-	540,000
Compensation expense related to stock options	-	-	68,000	-	-	68,000
Tax benefit from exercise of stock options	-	-	97,000	-	-	97,000
Balance, October 31, 2008	10,660,000	1,066,000	31,352,000	(982,000)	30,775,000	62,211,000
Comprehensive income(loss):						
Net (loss)	-	-	-	-	(14,454,000)	(14,454,000)
Purchase of treasury stock	-	-		(1,821,000)	-	(1,821,000)
Compensation expense related to stock options	-	-	31,000	-	-	31,000
Tax benefit from exercise of stock options	-	-	89,000	-	-	89,000
Balance, October 31, 2009	10,660,000	1,066,000	31,472,000	(2,803,000)	16,321,000	46,056,000
Comprehensive income(loss):						
Net income	-	-	-	-	2,203,000	2,203,000
Purchase of treasury stock	-	-		(2,066,000)	-	(2,066,000)
Compensation expense related to stock options	-	-	78,000	-	-	78,000
Exercise of stock options	-	-	(64,000)	360,000	-	296,000
Balance, October 31, 2010	10,660,000	$1,066,000	$31,486,000	$(4,509,000)	$18,524,000	$46,567,000

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Years Ended October 31, 2010

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2010	2009	2008
Cash flows from operating activities:			
Net income(loss)	$ 2,203,000	$(14,454,000)	$ 5,993,000
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Non-cash write-down of oil and natural gas properties and impairment of long lived assets	-	24,653,000	-
Depreciation, depletion and amortization	3,602,000	4,439,000	3,583,000
ARO liability accretion	75,000	77,000	51,000
Unrealized (gains) losses from derivatives	72,000	1,641,000	(1,301,000)
Deferred income taxes	744,000	(8,580,000)	1,913,000
(Gain) loss on short-term investments	(65,000)	180,000	618,000
Compensation expense related to stock options granted	78,000	31,000	68,000
Other	(1,000)	-	63,000
Changes in operating assets and liabilities:			
Proceeds from short-term investments	210,000	2,229,000	2,721,000
Purchase of short-term investments	(1,500,000)	-	-
Trade receivables	8,000	508,000	(393,000)
Accrued oil and gas sales	(8,000)	167,000	(86,000)
Other current assets	27,000	(654,000)	(150,000)
Accounts payable and accrued liabilities	(874,000)	(236,000)	(477,000)
Income taxes payable	(38,000)	(69,000)	(310,000)
Net cash provided by operating activities	4,533,000	9,932,000	12,293,000
Cash flows from investing activities:			
Additions to oil and gas properties	(8,525,000)	(13,719,000)	(9,544,000)
Proceeds from sale of oil and gas properties	299,000	-	-
Changes in other long-term assets	294,000	(65,000)	(1,652,000)
Purchase of intangible assets	-	(4,400,000)	(975,000)
Net cash used in investing activities	(7,932,000)	(18,184,000)	(12,171,000)
Cash flows from financing activities:			
Sale of common stock	-	-	15,095,000
Proceeds and the benefit from exercise of stock options	296,000	89,000	637,000
Purchase of treasury stock	(2,066,000)	(1,821,000)	(722,000)
Principal payment on exclusive license obligation	-	-	(85,000)
Net cash provided (used) by financing activities	(1,770,000)	(1,732,000)	14,925,000
Increase (decrease) in cash and cash equivalents	(5,169,000)	(9,984,000)	15,047,000
Cash and cash equivalents:			
Beginning of year	12,348,000	22,332,000	7,285,000
End of year	$ 7,179,000	$ 12,348,000	$ 22,332,000
Supplemental Cash Flow Information:			
Cash paid during the period for income taxes	$ -	$ -	$ 447,000
Additions to oil & gas properties included in current liabilities	$ 954,000	$ 74,000	$ 3,127,000

See accompanying notes to consolidated financial statements.

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Basis of Presentation

The consolidated financial statements include the accounts of Credo Petroleum Corporation and its wholly owned subsidiaries (the "company"). The company engages in oil and gas acquisition, exploration, development and production activities in the United States. All significant intercompany transactions have been eliminated. All references to years in these Notes refer to the company's fiscal October 31 year.

Cash, Cash Equivalents, and Short-Term Investments

Cash equivalents consist of liquid investments with original maturities of three months or less. During 2009 the company liquidated the majority of its short term investments in professionally managed limited partnerships. Other short term investments are directly invested in certificates of deposit and mutual funds. Short-term investments are classified as "trading" and are stated at fair value with realized and unrealized gains and losses immediately recognized.

Concentration of Credit Risk

Substantially all of the company's receivables are within the oil and natural gas industry, primarily from purchasers of oil and gas and from joint interest owners. These receivables are due from many companies with collectability being dependent upon the financial wherewithal of each individual company as well as the general economic conditions of the industry. The receivables are not collateralized. In the event that any individual monthly joint interest receivable becomes delinquent, the company has the ability to net the receivables against revenue distributions to the delinquent account. To date the company has had minimal bad debts.

Fair Value of Financial Instruments

The company's financial instruments including cash and cash equivalents, short term investments, accounts receivable and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments.

Revenue Recognition

The company derives its revenue primarily from the sale of produced crude oil and natural gas. The company reports revenue gross for the amounts received before taking into account production taxes and transportation costs which are reported as separate expenses. Revenue is typically recorded in the month production is delivered to the purchaser at which time title changes hands. Payment is generally received between 30 and 90 days after the date of production. 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, or when better information is available.

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.

Accounting Estimates

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 and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows therefrom, and the estimate of its asset retirement obligation.

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.

Oil and Gas Reserves

In December 2008, the Securities and Exchange Commission ("SEC") adopted revisions to its oil and gas disclosure requirements that are intended to align them with current practices and changes in technology. Among other things, the amendments: replace the single-day year-end pricing assumption with a twelve-month average pricing assumption; permit the disclosure of probable and possible reserves; allow the use of certain technologies to establish reserves; require the disclosure of the qualifications of the technical person primarily responsible for preparing the reserves estimates or conducting a reserves audit; require the filing of the independent reserve engineers' summary report; and permit the disclosure of a reserves sensitivity analysis table to illustrate the impact of different price and/or cost assumptions on reserves. These amendments are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009 (fiscal year 2010 for the company) with early adoption prohibited. The company adopted the revisions and amendments effective with this report on Form 10-K.

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. See Note 13 for further discussion of reserve estimates and the related uncertainties.

Asset Retirement Obligations

The company estimates the future cost of asset retirement obligations, discounts that cost to its present value, and records a corresponding asset and liability in its Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including future abandonment costs, inflation, 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:

	October 31, 2010	2009
Beginning asset retirement obligation	$ 1,502,000	$ 1,338,000
Accretion expense	75,000	77,000
Obligations incurred	27,000	87,000
Obligations settled (primarily from sale of assets)	(373,000)	1,000
Change in estimate	(99,000)	(1,000)
Ending asset retirement obligation	$ 1,132,000	$ 1,502,000

Environmental Matters

Environmental costs are expensed or capitalized depending on their future economic benefit. Costs that relate to an existing condition caused by past operations with no future economic benefit are expensed. Liabilities for future expenditures of a non-capital nature are recorded when future environmental expenditures and/or remediation is deemed probable and the costs can be reasonably estimated. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

Long-Lived Assets

The company applies FASB issued authoritative guidance to long-lived assets not included in oil and gas properties. Under the guidance, all long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value.

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.

The company believes that the number of future installations will be sufficient to demonstrate recoverability of the cost. Due to various factors, there have been no recent Calliope installations. If the Company is unable to achieve the expected level of installations, the company may in the future be required to record an impairment of the asset. Should this event occur, it would be a non-cash charge to income and would have no effect on working capital.

Income Taxes

The company accounts for income taxes in accordance with FASB issued authoritative guidance which requires the use of the asset and liability method of computing deferred income taxes. The objective of the asset and liability method is to establish deferred tax assets and liabilities for the temporary differences between the book basis and the tax basis of the company's assets and liabilities at enacted tax rates expected to be in effect when such amounts are realized or settled.

Oil and Natural Gas Derivatives

The company periodically uses derivatives as economic hedges of the price of a portion of its estimated production when the potential for significant downward price movement is anticipated. These transactions typically take the form of costless collars for oil and forward short positions based upon the NYMEX futures market for natural gas, and are closed by purchasing offsetting positions. Such contracts do not exceed estimated production volumes and are authorized by the company's Board of Directors. 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.

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 its Balance Sheet and changes in fair value are recorded in the Consolidated Statements of Operations as they occur.

Stock-Based Compensation

The company's 2007 Stock Option Plan (the "Plan") authorizes the granting of incentive and nonqualified options to purchase shares of the company's common stock. The maximum number of shares that may be made subject to grants is 1,000,000. The Plan is administered by the Board of Directors, which determines the terms pursuant to which any option is granted. The Plan provides that upon a change in control of the company, options then outstanding will immediately vest and the company will take such actions as are necessary to make all shares subject to options immediately salable and transferable. The company's 1997 Stock Option Plan, which was similar in all respects to the 2007 Plan, expired on July 29, 2007. No additional options can be granted under the 1997 Plan. However, all outstanding options granted under the 1997 Plan will continue to be governed by the terms of the 1997 Plan.

Per Share Amounts

Basic earnings (loss) per share is computed using the weighted average number of shares outstanding. Diluted earnings (loss) per share reflects the potential dilution that would occur if stock options were exercised using the average market price for the company's stock for the period.

The company's calculation of earnings (loss) per share of common stock is as follows:

	Year Ended October 31,								
	2010			2009			2008		
	Net Income (Loss)	Shares	Earnings (Loss) Per Share	Net Income	Shares	Earnings Per Share	Net Income	Shares	Earnings Per Share
Earnings(loss) per share-Basic	$ 2,203,000	10,183,000	$ 0.22	$(14,454,000)	10,326,000	$(1.40)	$5,993,000	9,697,000	$.62
Effect of dilutive shares of common stock from stock options ..	-	19,000	-	-	-	(-)	-	61,000	(.01)
Earnings(loss) per share-Diluted ..	$ 2,203,000	10,202,000	$ 0.22	$(14,454,000)	10,326,000	$(1.40)	$5,993,000	9,758,000	$.61

Ninety thousand (90,000) outstanding option shares were excluded from the diluted earnings per share calculation at October 31, 2010 as they would have been antidilutive because the exercise price exceeded the market price. Outstanding option shares (139,063) were excluded from the diluted loss per share calculation at October 31, 2009 as they would have been antidilutive due to the net loss for the year. Outstanding option shares (93,706) were excluded from the diluted earnings per share calculation at October 31, 2008 as they would have been antidilutive because the exercise price exceeded the market price.

(2) COMMON STOCK AND PREFERRED STOCK

The company has authorized 20,000,000 shares of $0.10 par value common stock and as of October 31, 2010, common shares issued are 10,660,000, common shares held in treasury are 601,000 and common shares outstanding are 10,059,000. In addition, the company has authorized 5,000,000 shares of preferred stock which may be issued in series and with preferences as determined by the company's Board of Directors. Approximately 100,000 shares of the company's authorized but unissued preferred stock have been reserved for issuance pursuant to the provisions of the company's Shareholders' Rights Plan.

During the quarter ended July 31, 2008 the company entered into, and closed, a Company Stock Purchase Agreement with RCH Energy Opportunity Fund II, LP (RCH). Under the terms of the agreement the company sold to RCH 1,150,000 shares of newly-issued common stock, par value $0.10 at a price of $14.50 per share, in cash. Transaction fees paid from the proceeds of sale were $1,580,000.

Also under the terms of the agreement, RCH nominated, and the company's Board of Directors elected, two new directors to serve on the company's Board of Directors for so long as RCH beneficially owns at least 15% of the company's outstanding stock and one director for so long as RCH beneficially owns at least 10% of the company's outstanding stock.

In connection with the Company Stock Purchase Agreement with RCH the company amended its Rights Agreement, dated as of April 11, 1989, as amended, in order to exempt the Common Stock Purchase Agreement from application of the Rights Agreement.

The company entered into a joint venture agreement, as amended, with RCH Energy Opportunity Fund II, LP, its affiliates and its General Partner, RR Advisors, LLC to use the Calliope Gas Recovery Technology on wells that they might propose to the joint venture. As of October 31, 2010, there have been no transactions under this agreement

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 October 31, 2010, the company has acquired 527,429 shares under the program, at an aggregate cost of $4,610,000.

Subsequent to October 31, 2010, and through January 13, 2011, the company has repurchased an additional 18,000 shares, bringing the total shares repurchased to 545,429 at an average price per share of $8.91.

(3) OIL AND NATURAL GAS PROPERTIES

Depreciation, depletion and amortization of oil and natural gas properties for the fiscal years ended October 31, 2010, 2009 and 2008 were $3,129,000, $3,931,000 and $3,446,000 respectively. 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. 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 wells in progress, 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 proved recoverable reserves or not, or if there is an impairment, the costs are reclassified to the full cost pool.

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. The ceiling test is calculated using oil and natural gas prices in effect as of the quarterly balance sheet date through the third fiscal quarter. For the fourth fiscal quarter, the average of prices on the first day of each month of the fiscal year was used for the calculation. 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, unless the company considers price increases subsequent to the balance sheet date which may reduce or eliminate a write-down. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

At October 31, 2010 the estimated present value of future net revenues from proved reserves, net of related income tax considerations, exceeded the capitalized costs of the company's oil and natural gas properties. Therefore, a ceiling test write-down was not required.

Due primarily to low natural gas prices during the first half of 2009, for the fiscal year ended October 31, 2009, the company recorded non-cash ceiling test write-downs at the end of the first and second quarters, in the aggregate of $23,726,000.

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 average of the prices on the first day of each month of the preceding twelve months 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 average prices and costs in effect during of the test period.

Marlis E. Smith, Jr., a member of the Company's Board of Directors since April 2009 and the Company's President and Chief Executive Officer since January 16, 2010, has participated as an independent third party working interest owner in numerous oil and gas wells operated by Credo. During Credo's fiscal year ended October 31, 2010, Mr. Smith owned interests in fifty six such properties, most of which he owned before becoming an officer and director of Credo. During that period, he received approximately $292,000 in oil and gas revenues and paid approximately $186,000 in drilling costs and operating expenses related to such interests. He also owns interests in numerous wells which are operated by third parties and in which Credo also owns an interest.

(4) STOCK BASED COMPENSATION

The following table summarizes stock option activity in the company's stock-based compensation plans for the years ended October 31, 2010, 2009 and 2008.

	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE	AGGREGATE INTRINSIC VALUE (1)	NUMBER OF SHARES EXERCISABLE	WEIGHTED AVERAGE FAIR VALUE AT GRANT DATE
Outstanding at October 31, 2007 ..	270,251	$ 6.94	$ 875,000	236,918	$ 729,000
Granted at premium to fair value .	53,706	14.31			
Exercised	(91,188)	5.93	415,000		
Outstanding at October 31, 2008 ..	232,769	9.04	394,000	157,397	680,000
Cancelled	(53,706)	14.31			
Outstanding at October 31, 2009 ..	179,063	7.46	530,000	169,063	511,000
Granted at fair value	50,000	9.30			
Exercised	(50,000)	5.93			
Outstanding at October 31, 2010 ..	179,063	$ 8.40	$ 184,000	124,063	$ 565,000

(1) The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option at October 31 of each year. If the exercise price exceeds the market value, there is no intrinsic value.

The fair value of the stock option grants are amortized over the respective vesting period using the straight-line method and assuming no forfeitures and cancelations. Based on the historical experience of the company, forfeitures and cancellations are not significant. The large forfeiture and cancellation in 2009 was not material due to the short period of time that the options were outstanding. Compensation expense related to stock options included in General and Administrative Expense for the years ended October 31, 2010, 2009 and 2008 are $78,000, $31,000 and $68,000 respectively. The estimated unrecognized compensation cost from unvested options as of October 31, 2010 was approximately $127,000, which is expected to be recognized over an average period of 2.2 years.

Stock options, except those granted at a premium in 2008, are granted at the fair market value of one share of Common Stock on the date of grant. Options granted to non-employee directors vest 1/3 immediately and 1/3 on each subsequent anniversary. Options granted to officers and other employees vest over three to four years. All outstanding options had a term of ten years at the date of grant.

The fair value of each option granted in 2010, 2009 and 2008 was estimated using the Black-Scholes option pricing model. The following assumptions were used to compute the weighted average fair value of options granted during the periods presented.

	2010	2009	2008
Expected life of options	3 years	N/A - No grants in 2009	5 years
Risk free interest rates	2.69%		2.93%
Estimated volatility	51.60%		49.41%
Dividend yield	0.00%		0.00%
Weighted average fair market value of options granted during the year.	$ 3.46		$ 3.15

The following table summarizes information about options outstanding at October 31, 2010.

Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Aggregate Intrinsic Value	Number Exercisable	Weighted Average Exercise Price	Aggregate Intrinsic Value
$ 5.93	89,063	2.6	$ 5.93	$ 184,000	89,063	5.93	184,000
12.78	40,000	6.1	12.78	-	35,000	12.78	-
9.30	50,000	9.2	9.30	-	-	9.30	-
$5.93 - $12.78	179,063	5.2	$ 8.40	$ 184,000	124,063	7.86	$ 184,000

(5) 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. These transactions typically take the form of costless collars for oil and forward short positions based upon the NYMEX futures market for natural gas, and are closed by purchasing offsetting positions. Such contracts do not exceed estimated production volumes and are authorized by the company's Board of Directors. 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 October 31, 2010 the company held open derivative contracts representing natural gas short sales positions for 40,000 MMBtus at NYMEX basis prices ranging from $6.91 to $7.27 and covering the production months of November and December 2010. The company also held open offsetting derivative contracts with the same counterparty for 40,000 MMBtus at NYMEX basis prices of $5.83 and covering the production months of November through December 2010. These positions are presented net due to the contractual netting provisions with the counterparty. The open derivative contracts net to an unrealized gain of $50,000 at October 31, 2010. Average natural gas prices received in the company's primary market have historically been 15% - 17% below NYMEX prices due to basis differentials compared to the current differentials of about 4%.

At October 31, 2010 the company also held natural gas basis differential hedges on 80,000 MMBtus with NYMEX vs. Panhandle Eastern Pipeline basis differentials of $0.47 and covering the production months of November and December 2010. These open basis differential contracts represent unrealized losses of $19,000 at October 31, 2010.

Subsequent to October 31, the November and December natural gas related derivative contracts closed, resulting in net realized derivative gains of $50,000. Subsequent to October 31, 2010, the company also entered into natural gas derivative contracts for 30,000 MBTU's for each of production months of January, February and March 2011. These contracts are at NYMEX Basis prices of $4.35-4.52 per Mcf.

Also subsequent to October 31, 2010 the company entered into costless collar derivative contracts for 5,000 barrels of oil for each production month of calendar year 2011 with a floor of $80.00 and a ceiling ranging from $90.50 to $97.50 per barrel. The company also entered into costless collar derivative contracts for 3,000 barrels of oil for each production month of calendar year 2012 with a floor of $80.00 and a ceiling ranging from $94.00 to $99.00 per barrel.

The location and amount of derivative fair values and related gain (loss) are indicated in the following tables.

Derivatives not designated as hedging instruments:

	As of October 31, 2010	
	Balance Sheet Location	Fair Value
Natural Gas Forward Short and Long Positions and Basis Swaps	Derivative Asset	$ 32,000

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

	Location of Gain/(Loss) Recognized in Income on Derivatives	Year Ended Oct. 31, 2010
Natural Gas Forward Short and Long Positions and Basis Swaps	Other Income and (Expense)	$ 42,000

The company has a derivative 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 available is $7,200,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the company's bank, and prohibits funded debt in excess of $500,000. The line expires May 1, 2013.

(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 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.

As of October 31, 2010 the company's 2007 Federal tax return had been audited by the IRS, and the final report reflected approximately $24,000 in additional tax due. The company remains subject to examination of 2008 and 2009 Federal and 2007 through 2009 state tax returns, except Colorado, in which the 2006 tax year also remains open.

At October 31, 2010 the company had $3,659,000 of statutory depletion carry forward for tax return purposes.

The income tax expense recorded in the Consolidated Statements of Operations consists of the following:

	Years Ended October 31,		
	2010	2009	2008
Current	$ (132,000)	$ (481,000)	$ 247,000
Deferred	744,000	(8,580,000)	1,913,000
Total income tax expense	$ 612,000	$ (9,061,000)	$ 2,160,000

The effective income tax rate differs from the U.S. Federal statutory income tax rate due to the following:

	Years Ended October 31,		
	2010	2009	2008
Federal taxes at statutory rate	$ 985,000	$ (8,216,000)	$2,853,000
Graduated rates	(15,000)	244,000	(56,000)
State income taxes and other	144,000	(742,000)	210,000
Percentage depletion	(502,000)	(347,000)	(847,000)
	$ 612,000	$ (9,061,000)	$2,160,000

The principal sources of temporary differences resulting in deferred tax assets and liabilities at October 31, 2010 and 2009 are as follows (certain prior year amounts have been reclassified for comparative purposes):

	October 31,	
	2010	2009
Deferred tax assets:		
Percentage depletion carryforward............	$ 1,244,000	$ 756,000
Intangible assets...........................	248,000	282,000
Net operating loss carry forward.............	1,150,000	-
Total deferred tax assets....................	2,642,000	1,038,000
Deferred tax liabilities:		
Oil and gas assets...........................	(5,635,000)	(3,483,000)
Derivative instruments.......................	(8,000)	(32,000)
State taxes..................................	(318,000)	(201,000)
Other	38,000	141,000
Total deferred tax liabilities...............	(5,923,000)	(3,575,000)
Net deferred tax liability	$ (3,281,000)	$ (2,537,000)

(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 natural gas production. These derivatives are carried at fair value on the consolidated balance sheets. Additionally, the company's short-term investments consist primarily of professionally managed limited partnerships which include investments that are not publicly traded and may have less readily determinable market values. The accounting standards established 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 a 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 following table provides the assets and liabilities carried at fair value measured on a recurring basis as of October 31, 2010:

	Level 1	Level 2	Level 3	Total
		(in thousands)		
Asset:				
Short-term investments	$ 1,865	$ -	$ 125	$ 1,990
Derivative assets (current)	$ -	$ 32	$ -	$ 32

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 to determine the valuation of its investment. Fair values derived from the statements are further substantiated by current fund redemption activity and communication with investment advisors.

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 fiscal year ended October 31, 2010:

	(in thousands)
Balance as of October 31, 2009 (1)	$ 342
Total gains or losses (realized or unrealized) included in earnings (2)	(7)
Redemptions	(210)
Balance as of October 31, 2010	$ 125

(1) This amount is included in short term investments on the balance sheet.
(2) This amount is included in investment income (loss) on the statement of operations.

(8) 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.

The company believes that the number of future installations will be sufficient to demonstrate recoverability of the cost. Due to various factors, there have been no recent Calliope installations. If the Company is unable to achieve the expected level of installations, the company may in the future be required to record an impairment of the asset. Should this event occur, it would be a non-cash charge to income and would have no effect on working capital or the functional value of the Calliope Gas Recovery System.

	October 31, 2009		October 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets:				
Calliope intangible assets	$ 4,449,000	$ 436,000	$ 4,449,000	$ 872,000
Aggregate amortization expense:				
For the years ended October 31, 2009 and 2010		$ 436,000		$ 436,000

Estimated future amortization expense:

For the year ended October 31, 2011	$ 436,000
For the year ended October 31, 2012	436,000
For the year ended October 31, 2013	436,000
For the year ended October 31, 2014	436,000
Thereafter	1,833,000
Total	$ 3,577,000

In July 2008, near the peak of historic natural gas prices, the company acquired the third party rights in producing properties and possible future Calliope installations for $975,000. As a result of the natural gas price collapse at January 31, 2009, the company determined that the sum of the undiscounted value of cash flows to be derived was minimal. Accordingly, the company recorded an impairment loss of $927,000 for the quarter ended January 31, 2009.

(9) COMPRESSOR, TUBULAR AND CALLIOPE INVENTORY

Compressor and tubular inventory are finished goods, recorded at cost, which are expected to be used in the future development of the company's oil and gas properties. The company has classified this inventory 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.

(10) BENEFIT PLANS

Profit Sharing 401(k) Plan

The company has established a 401(k) plan for the benefit of its employees. Eligible employees may make voluntary contributions not exceeding statutory limitations to the plan. These contributions may be matched by the company, at its discretion. Historically, the company has made matching contributions ranging from 40% to 50% of the employees annual contributions. Matching contributions recorded in fiscal 2010, 2009 and 2008 were $44,000 in each year.

Other Company Benefits

The company provides a health and welfare benefit plan to all regular full-time employees. The plan includes health insurance.

(11) COMMITMENTS AND CONTINGENCIES

The company leases office facilities under an operating lease agreement entered into May 1, 2006 which expires April 30, 2011. The lease agreement requires payments of $32,000 in each year through 2010, and $15,000 in 2011. Total rental expense was $105,000 in 2010, $107,000 in 2009, and $78,000 in 2008. The company has no capital leases and no other operating lease commitments at October 31, 2010. Subsequent to October 31, 2010, the company extended its office lease to cover the period of May 1, 2010 through April 30, 2015 at a monthly rate of $3,802 plus operating expenses.

The company was named as a defendant in a lawsuit alleging breach of contract, and other issues, arising in the normal course of its oil and gas activities. The suit was settled August 11, 2010 at a cost of $25,000 to Credo.

The company has also been named as a defendant in a lawsuit brought by a former employee. The suit alleges breach of contract and other employment issues. Although the company believes the allegations are without merit and that the company will ultimately prevail, the ultimate outcome of this lawsuit cannot be determined at this time.

(12) SUPPLEMENTARY OIL AND GAS INFORMATION

Capitalized Costs

	October 31,		
	2010	2009	2008
Unevaluated properties not being amortized	$ 8,801,000	$ 7,363,000	$ 12,280,000
Properties being amortized	83,360,000	76,127,000	59,730,000
Accumulated depreciation, depletion and amortization...........	(56,339,000)	(53,211,000)	(25,554,000)
Total capitalized costs	$ 35,822,000	$ 30,279,000	$ 46,456,000

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 year incurred, the unevaluated oil and gas property costs (net of transfers to the full cost pool and sales proceeds) excluded from the amortization computation as of October 31, 2010:

Net Costs Incurred During Years Ended:	Total Unevaluated Properties
October 31, 2010	$ 2,656,000
October 31, 2009	3,786,000
October 31, 2008 and prior	2,359,000
	$ 8,801,000

Prospect leasing and acquisition normally requires one to two years and the subsequent evaluation normally requires an additional one to two years.

Acquisition, Exploration and Development Costs Incurred (Net of Sales)

	Years Ended October 31,		
	2010	2009	2008
Property acquisition costs net of divestiture proceeds:			
Proved..........................	$ -	$ -	$ 442,000
Unproved.........................	3,102,000	4,364,000	6,539,000
Exploration costs	4,393,000	4,826,000	4,057,000
Development costs	1,207,000	2,203,000	1,219,000
Total before asset retirement obligation	$ 8,703,000	$ 11,393,000	$ 12,257,000
Total including asset retirement obligation	$ 8,730,000	$ 11,480,000	$ 12,528,000

Major Customers and Operating Region

The company operates exclusively within the United States. Except for cash investments, all of the company's assets are employed in, and all its revenues are derived from, the oil and gas industry. The company had sales in excess of 10% of total revenues to oil and gas purchasers as follows: DCP Midstream LLP 13% in 2010, 28% in 2009, and 49% in 2008, Coffeeville Resources 24% in 2010 and 37% in 2009.

Oil and Gas Reserve Data (Unaudited)

At October 31, 2010, 2009 and 2008, LaRoche Petroleum Consultants, Ltd., an independent petroleum engineering firm, estimated proved reserves for all of the company's properties.

Reserve definitions and pricing requirements prescribed by the Securities and Exchange Commission were used. The determination of oil and gas reserve quantities involves numerous estimates which are highly complex and interpretive. The estimates are subject to continuing re-evaluation, and reserve quantities may change as additional information becomes available. For 2010, the prices were calculated based on the average of spot prices on the first day of each month during the fiscal year. For 2009 and 2008 the prices were calculated based on the spot price on the last day of the fiscal year. The average price used was $68.30, $69.24, and $62.25 per barrel for oil and $4.49, $4.49, and $3.50 per Mcf for gas in 2010, 2009, and 2008, respectively. Estimated future costs were calculated assuming continuation of costs and economic conditions at the reporting date.

Prior period data presented throughout this footnote is not required to be, nor has it been, updated based on the new guidance. The effect of adopting the new guidance did not significantly impact the Company's estimated quantity of total proved reserves as of October 31, 2010.

The company's reserves, and reserve values, are concentrated in 65 properties ("Significant Properties"). Some of the Significant Properties are individual wells and others are multi-well properties. At October 31, 2010, the Significant Properties represent 23% of the company's total number of properties but a disproportionate 80% 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 15% of the number of Significant Properties and represent 15% of the discounted reserve value of such properties. Reserve additions in 2010 comprises 9% of the Significant Properties and represent 6% of the discounted value of such properties.

Estimates of reserve quantities and values for certain 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 Calliope 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.

One measure of the life of the company's proved reserves can be calculated by dividing proved reserves at fiscal year end 2010 by production for fiscal year 2010. This measure yields an average reserve life of 12.1 years. 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, their 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.

Total estimated proved reserves and the changes therein are set forth below for the indicated year.

	2010		2009		2008	
	Oil(bbls)	Gas(Mcf)	Oil(bbls)	Gas(Mcfs)	Oil(bbls)	Gas(Mcf)
Proved reserves:						
Balance, Beginning of year	876,000	14,940,000	710,000	15,525,000	591,000	16,973,000
Revisions of previous estimates......	6,000	(386,000)	(1,000)	247,000	(82,000)	(4,206,000)
Extensions and discoveries............	164,000	345,000	283,000	381,000	248,000	3,935,000
Purchases of reserves in place.......	5,000	412,000	-	16,000	9,000	368,000
Sales of reserves in place...............	-	(335,000)	-	-	-	-
Production...............	(97,000)	(1,038,000)	(116,000)	(1,229,000)	(56,000)	(1,545,000)
Balance, October 31.......	954,000	13,938,000	876,000	14,940,000	710,000	15,525,000
Proved developed reserves:						
Beginning of year.........	454,000	9,633,000	449,000	10,621,000	458,000	12,890,000
End of year..............	501,000	8,971,000	454,000	9,633,000	499,000	10,621,000

The standardized measure of discounted future net cash flows from reserves is set forth below as of October 31 of the indicated year.

	2010	2009	2008
Future cash inflows	$ 127,672,000	$127,731,000	$ 98,560,000
Future production and development costs	(57,807,000)	(55,868,000)	(44,905,000)
Future income tax expense	(14,898,000)	(15,119,000)	(9,119,000)
Future net cash flows	54,967,000	56,744,000	44,536,000
10% discount factor	(24,037,000)	(24,144,000)	(16,917,000)
Standardized measure of discounted future net cash flows	$ 30,930,000	$ 32,600,000	$ 27,619,000

The principal sources of changes in the standardized measure of discounted future net cash flows from reserves are set forth below for the indicated year.

	2010	2009	2008
Balance at beginning of year	$ 32,600,000	$ 27,619,000	$ 46,801,000
Sales of oil and gas produced, net of production costs	(8,375,000)	(6,807,000)	(13,484,000)
Net changes in prices and production costs	(51,000)	10,670,000	(17,290,000)
Extensions and discoveries	3,979,000	5,231,000	11,134,000
Changes in future development costs ..	(2,403,000)	(1,533,000)	(2,485,000)
Previously estimated development costs incurred during the period	1,246,000	1,499,000	1,506,000
Revisions of previous quantity estimates, timing, and other	(842,000)	(3,670,000)	(10,116,000)
Purchases of reserves in place	1,060,000	34,000	866,000
Sales of reserves in place	(361,000)	-	-
Accretion of discount	4,043,000	2,679,000	5,811,000
Net change in income taxes	34,000	(3,122,000)	4,876,000
Balance, October 31	$ 30,930,000	$ 32,600,000	$ 27,619,000

(13) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following is a tabulation of the company's unaudited quarterly operating results for fiscal 2010, 2009 and 2008.

	Oil & Gas Sales	Income (Loss) Before Income Taxes	Net Income (Loss)	Basic Earnings (Loss) Per Share	Diluted Earnings (Loss) Per Share
Fiscal 2008:					
First Quarter	$ 3,733,000	$ 2,221,000	$ 1,573,000	$ 0.17	$ 0.17
Second Quarter	4,942,000	(1,233,000)	(880,000)	(0.09)	(0.09)
Third Quarter	5,646,000	4,607,000	3,343,000	0.35	0.34
Fourth Quarter	3,024,000	2,558,000	1,957,000	0.19	0.19
	$ 17,345,000	$ 8,153,000	$ 5,993,000	$ 0.62	$ 0.61
Fiscal 2009:					
First Quarter	$ 2,108,000	$ (16,281,000)	$ (9,891,000)	$ (0.95)	$ (0.95)
Second Quarter	2,353,000	(7,655,000)	(4,710,000)	(0.46)	(0.46)
Third Quarter	2,837,000	580,000	353,000	0.03	0.03
Fourth Quarter	2,769,000	(159,000)	(206,000)	(0.02)	(0.02)
	$ 10,067,000	$ (23,515,000)	$ (14,454,000)	$ (1.40)	$ (1.40)
Fiscal 2010:					
First Quarter	$ 3,142,000	$ 864,000	$ 639,000	$ 0.06	$ 0.06
Second Quarter	2,945,000	793,000	603,000	0.06	0.06
Third Quarter	2,917,000	708,000	555,000	0.06	0.06
Fourth Quarter	2,562,000	450,000	406,000	0.04	0.04
	$ 11,566,000	$ 2,815,000	$ 2,203,000	$ 0.22	$ 0.22

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of CREDO Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Credo Petroleum Corporation and subsidiaries as of October 31, 2010 and 2009, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended October 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Credo Petroleum Corporation and subsidiaries at October 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended October 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Credo Petroleum Corporation's internal control over financial reporting as of October 31, 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated January 13, 2011 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
January 13, 2011

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of CREDO Petroleum Corporation

We have audited Credo Petroleum Corporation's internal control over financial reporting as of October 31, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Credo Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Credo Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of October 31, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Credo Petroleum Corporation and subsidiaries as of October 31, 2010 and 2009 and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended October 31, 2010 and our report dated January 13, 2011 expressed an unqualified opinion thereon.

Ernst & Young LLP

Denver, Colorado
January 13, 2011

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Attached as exhibits to this report are certifications of our CEO and CFO required pursuant to Rule 13a-14 under the Exchange Act. This section includes information concerning the controls and procedures evaluation referred to in the certifications.

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of October 31, 2010. This evaluation was conducted under the supervision and with the participation of management, including our

CEO and CFO. Based on this evaluation, our CEO and CFO have concluded that, subject to the limitations noted in this section, as of October 31, 2010, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC. We also concluded that our disclosure controls and procedures are effective to provide reasonable assurance 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 CEO and CFO, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets of the company, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Under the supervision and with the participation of our management, including our CEO and CFO, we assessed our internal control over financial reporting as of October 31, 2010, the end of our fiscal year. This assessment was based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, management has concluded that our internal control over financial reporting was effective as of October 31, 2009.

The effectiveness of our internal control over financial reporting as of October 31, 2010 has been audited by Ernst & Young LLP, our independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting during the quarterly period ended October 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Effectiveness of Controls. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Pursuant to instruction G (3) to Form 10-K, Items 10, 11, 12, 13 and 14 are incorporated herein by reference from the company's definitive proxy statement for its annual meeting of stockholders to be filed with the United States Securities and Exchange Commission within 120 days after the end of the fiscal year ended October 31, 2009.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Schedules are omitted because of the absence of the conditions under which they are required or because the information is included in the financial statements or notes to the financial statements.

(b)	Exhibits. The following exhibits are filed with or incorporated by reference into this report on Form 10-K.
3(i)	Amended and Restated Certificate of Incorporation of CREDO Petroleum Corporation, a Delaware corporation (incorporated herein by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on April 10, 2009).
3(ii)	Bylaws of CREDO Petroleum Corporation, a Delaware corporation (incorporated herein by reference to Exhibit 3.2 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on April 10, 2009).
4.1	Shareholders' Rights Plan, dated April 11, 1989.
4.2	Amendment to Shareholders' Rights Plan, dated February 24, 1999 (incorporated into Part II of the company's Form 10-QSB dated January 31, 1999).
4.3	Second Amendment to Rights Agreement, dated as of June 3, 2008, by and between the Company and Computershare Trust Company, N.A. (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 3, 2008).
4.4	Third Amendment dated as of April 9, 2009 to Rights Agreement dated as of April 11, 1989 between Credo Petroleum Corporation, a Delaware corporation, and Computershare Trust Company, N.A. (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on April 10, 2009).
4.5	Rights Agreement, dated April 9, 2009 between Credo Petroleum Corporation, a Delaware corporation and Computershare Trust Company, N.A. (incorporated herein by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on April 10, 2009).
10.1	CREDO Petroleum Corporation 1997 Stock Option Plan, as amended and restated effective October 25, 2001 (incorporated by reference to Form 10-KSB dated October 31, 2001).

10.2	CREDO Petroleum Corporation 2007 Stock Option Plan (incorporated by reference to the company's definitive proxy statement filed with the SEC on February 20, 2007).
10.3	Employment Agreement by and between CREDO Petroleum Corporation and Marlis E. Smith, Jr. dated as of December 21, 2009, effective as of January 16, 2010 (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 28, 2009).
14.1	Code of Business Conduct and Ethics (incorporated by reference to Form 10-KSB dated October 31, 2004).
21	CREDO Petroleum Corporation (a Delaware corporation) and its subsidiaries SECO Energy Corporation (a Nevada corporation) and United Oil Corporation (an Oklahoma corporation) are located at 1801 Broadway, Suite 900, Denver, CO 80202-3837.
23.1 *	Consent of Independent Registered Public Accounting Firm dated January 12, 2009.
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).
99.1*	LaRoache Petroleum Consultants, Ltd. Reserve Report.

* Filed with this Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 in the City of Denver, State of Colorado on January 13, 2011.

CREDO PETROLEUM CORPORATION
(Registrant)

By:/s/ Marlis E. Smith, Jr.
Marlis E. Smith, Jr.,
Chief Executive Officer

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date	Signature	Title
January 13, 2011	/s/ Marlis E. Smith, Jr. Marlis E. Smith, Jr.	Director and Chief Executive Officer (Principal Executive Officer)
January 13, 2011	/s/ Alford B. Neely Alford B. Neely	Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)
January 13, 2011	/s/ James T. Huffman James T. Huffman	Chairman of the Board of Directors
January 13, 2011	/s/ Clarence H. Brown Clarence H. Brown	Director
January 13, 2011	/s/ Oakley Hall Oakley Hall	Director
January 13, 2011	/s/ W. Mark Meyer W. Mark Meyer	Director
January 13, 2011	/s/ John A. Rigas John A. Rigas	Director
January 13, 2011	/s/ H. Leigh Severance H. Leigh Severance	Director
January 13, 2011	/s/ William F. Skewes William F. Skewes	Director

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Board of Directors and Corporate Information

Directors

Clarence H. Brown
Petroleum Engineer and
Independent Businessman
Westminster, Colorado

Oakley Hall
Retired PricewaterhouseCoopers Partner
and Independent Businessman
Kingwood, Texas

James T. Huffman
Chairman; Retired Chief Executive Officer
of the Company
Denver, Colorado

W. Mark Meyer
Petroleum Engineer and
Equity Fund Manager
Houston, Texas

John A. Rigas
Petroleum Engineer and
Equity Fund Manager
Houston, Texas

H. Leigh Severance
Independent Businessman
Capital Management Co Owner
Denver, Colorado

William F. Skewes
Attorney
Denver, Colorado

Marlis E. Smith, Jr.
President and Chief Executive Officer
Denver, Colorado

Executive Officers

Marlis E. Smith, Jr.
President and Chief Executive Officer
Denver, Colorado

James T. Huffman
Chairman; Retired Chief Executive Officer

Alford B. Neely
Chief Financial Officer,
Secretary and Treasurer

Executive Offices

1801 Broadway, Suite 900
Denver, Colorado 80202
(303) 297-2200
Website: www.credopetroleum.com

Corporate Counsel

Davis Graham & Stubbs LLP
Denver, Colorado

Hall, Estill, Hardwick, Gable,
Gordon & Nelson, P.C.
Oklahoma City, Oklahoma

Independent Registered Public Accounting Firm

Ernst & Young LLP
Denver, Colorado

Registrar and Transfer Agent

Computershare Trust Company, Inc.
350 Indiana Street, Suite 800
Golden, Colorado 80401

Stock Exchange and Trading Range

NASDAQ Global Market
NASDAQ Symbol: CRED

Market quotations shown below were reported by the National Association of Securities Dealers, Inc. and represent prices between dealers excluding retail mark-up or commissions.

	2010		2009	
Fiscal Quarter Ended	High	Low	High	Low
Jan. 31	$ 10.52	$ 8.70	$ 10.21	$ 7.86
April 30	10.47	8.40	9.53	6.73
July 31	9.91	7.13	12.87	8.08
Oct. 31	8.63	7.67	12.90	9.72

At February 11, 2011, the company had 2,209 shareholders of record. The company has never paid a cash dividend and does not expect to pay any cash dividends in the foreseeable future. Earnings are reinvested in business activities.

CREDO Petroleum Corporation
1801 Broadway, Suite 900
Denver, CO 80202
(303) 297-2200
www.credopetroleum.com