CREDO PETROLEUM CORP
Form 10-K
January 07, 2010
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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, 2009

or

o 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: o 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: o 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 o 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). o Yes o 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 o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of April 30, 2009, the end of the registrant s most recently completed second quarter was $76,795,000.

As of January 4, 2010, the registrant had 10,204,000 shares of common stock outstanding.

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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 8, 2010 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 13 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;
- effectiveness of the company s hedging transactions;
- investment strategy and risk; and
- expansion and growth of the company s business and operations.

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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.

Prior to 2006, the company s core drilling region was the northern shelf of the Anadarko Basin in Oklahoma and North Texas where it explored primarily for natural gas. As a result, a significant majority of the company s reserves have historically been comprised 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 exploration projects in central Kansas, the Williston Basin of North Dakota and South Texas. 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.

Compared to drilling in Oklahoma, the North Dakota and South Texas projects involve higher costs and greater risks but have significantly higher per well reserve potential. In contrast, drilling in central Kansas is less expensive than the company s Oklahoma drilling projects while still yielding excellent economics. Depending on natural gas prices, the company will continue generating prospects and drilling on its Oklahoma and South Texas acreage concentrating on medium depth properties. Refer to Item 2 Properties General for further information about these drilling projects.

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, Texas and Louisiana 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

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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 135 wells pursuant to standard industry operating agreements. The company owns working interests in about 350 producing wells and overriding royalty interests in about 1,200 wells.

Refer to Item 2., Properties , for more information regarding the company s properties 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, 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.

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 increasing due to 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 and $3.50 in October, 2009. The company expects natural gas prices to return to more historical levels but 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.

Oil production is sold to crude oil purchasing companies 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. Crude oil prices were strong through mid-2008 due to supply concerns in view of the demand growth expected from developing countries such as China and India. However, the economic crisis that commenced in the second half of 2008 resulted in reduced demand projections and oil prices crashed from about $140 per barrel (NYMEX basis) in July 2008 to about $35 per barrel in February, 2009. Prices have since recovered to the $70 to $80 per barrel range.

Information concerning the company s major customers is included in Note (13) to the Consolidated Financial Statements.

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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 2010. 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 14 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 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

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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.

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, 2009, approximately 36% 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 some time 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.

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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 has based the PV-10 on prices and costs as of the date of the reserve estimate, in accordance with applicable regulations. 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. 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 .

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, unless the company considers price increases subsequent to the balance sheet date which may reduce or eliminate a write-down. 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 64 properties which represent 22% 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 16% of these significant properties and 14% of the discounted reserve value of such properties. Reserves added during 2009 comprise 8% of these significant properties and 14% 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.

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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 natural gas, the company periodically enters into derivative transactions for a portion of its estimated natural gas production. These transactions may limit the company s potential gains if natural gas 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 natural gas 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 derivatives are generally based on NYMEX prices but the company s hedged production is primarily sold on a regional pipeline index price. The regional price is currently 2% below NYMEX prices. However, regional weather conditions and other economic factors can frequently result in substantially higher basis differentials.

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.

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The company has recently expanded the volume and breadth of its exploration program with new drilling projects in South Texas and North Dakota. Compared to the company s Oklahoma drilling, these projects involve higher costs and greater risks.

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 located on the northern shelf of the Anadarko Basin of Oklahoma and North Texas 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 area. However, in recent years the company has diversified its drilling activities into other regions and has deemphasized drilling for natural gas in favor of drilling for crude oil reserves. Continued drilling on the company s Oklahoma and North Texas 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 central Kansas, North Dakota s Williston Basin, and South Texas. Compared to drilling in Oklahoma, the North Dakota and South Texas projects involve higher costs and greater risks but significantly higher per well reserve potential. In contrast, drilling in central Kansas is less expensive than the company s Oklahoma drilling projects while still yielding excellent economics.

In central Kansas, the company owns interests in approximately 140,000 gross acres and 77,000 net acres and it is continuing to expand its acreage position. At October 31, 2009, the company has

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participated in drilling 44 wells on its acreage, of which 43% 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. The company owns working interests in the existing prospects ranging from 12.5% to 85%. The company s north-central Kansas drilling activities provide diversification to the company s drilling program geographically and scientifically 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 older technology. Drilling targets the Lansing-Kansas City and Arbuckle formations at about 4,000 feet and, compared to the company s Northern Anadarko Basin, North Dakota Bakken, and South Texas projects, is relatively low cost, low risk, and exclusively targets oil reserves.

In North Dakota s Bakken oil shale play, the company has assembled approximately 7,600 gross and 5,675 net acres on the Fort Berthold Indian Reservation south and west of Parshall Field. The acreage consists of approximately 33 drilling locations based on 640 acre spacing units and 13 locations based on 1,280 acre 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 Three Forks shales. Breakthroughs in precision horizontal drilling and multi-stage, high pressure fracture stimulations have made the Bakken shale a very active resource play which is being actively developed by a significant number of companies, including large independents and majors. The U.S. Geological Survey recently estimated that the Bakken contains around 4.0 billion barrels of undiscovered oil. 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. Drilling is complete on the first Bakken horizontal well in which the company owns an interest and the well is currently awaiting completion which has been delayed due to cold weather and is now expected to commence in February 2010. The horizontal leg of the well is approximately 9,200 feet and will be completed in multiple stages. Credo owns a 10% working interest. Work is currently under way in preparation for drilling two to three additional wells on company acreage.

The South Texas project is 3-D seismic driven with well depths ranging from 10,000 to 17,000 feet. The most significant well drilled to date tested the Deep Wilcox formation on the Gemini Prospect and resulted in a dry hole. The 17,000-foot well confirmed the seismic interpretation and found porous sand. However, the sand was water wet and the well was plugged and abandoned. The company received approximately $1,300,000 of cash for the multiple prospect package and retained an 11.25% carried interest in the test well. The prospect package sold consists of two additional Deep Wilcox prospects located to the north of Gemini Prospect. These two prospects are structurally different and unique compared to the Gemini Prospect. Those prospects are being further evaluated, and if drilled, the company will have the same 11.25% carried interest in the next well as it did in the Gemini Prospect test well. This project is highly dependent on natural gas prices and is currently on hold due to low natural gas prices.

The company owns the patents covering Calliope and 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 more than 1,000 wells that meet its general criteria for Calliope candidate wells and thousands more that will meet its general Calliope 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, 14 of the wells

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were dead, nine were uneconomic and two were marginal. There are 14 non-experimental Calliope wells. As a group, those wells were producing a total of 88 thousand cubic feet of gas per day at the time Calliope was installed. Since Calliope was installed, those wells have produced 5.4 billion cubic feet of gas and they now have estimated ultimate (8/8ths) Calliope reserves totaling 7.0 billion cubic feet of gas. Ten 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.

On November 6, 2008 the company purchased all of the patents underlying Calliope, all of the related third party interests in future installations of the technology and 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. During fiscal 2009, a joint venture agreement for a pilot project was completed with a large independent and joint venture discussions are underway with several companies, both large and small.

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

The company s reserves, and reserve values, are concentrated in 64 properties (Significant Properties). Some of the Significant Properties are individual wells and others are multi-well properties. At year-end, Significant Properties represent 22% 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 16% of the Significant Properties and represent 14% of the discounted reserve value of such properties. Reserves added in 2009 comprise 8% of the Significant Properties and represent 14% of the discounted value of such properties.

Estimates of reserve quantities and values for certain Significant Properties must be viewed as being subject to significant change as more data about the properties becomes available. Such properties include wells with limited production histories and properties with proved undeveloped or proved non-producing reserves. In addition, Calliope wells are generally 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.

At October 31, 2009 and 2008, LaRoche Petroleum Consultants, Ltd., an independent petroleum engineering firm, estimated proved reserves for all of the company s properties. In 2007 McCartney Engineering, Inc., an independent petroleum engineering firm, estimated proved reserves for the company s properties which represented 64% of the total estimated future value of estimated reserves. In 2007, remaining reserves were estimated by the company. At October 31, 2009, natural gas represented 74% and crude oil represented 26% of total reserves denominated in equivalent Mcf s using a six Mcf of gas to one barrel of oil conversion ratio.

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 (11) to the Consolidated Financial Statements where additional reserve information is provided. The average price used to calculate estimated future net revenues was $4.49, $3.50, and $5.89 per Mcf of gas and $69.24, $62.25, and $86.61 per barrel of oil as of October 31, 2009, 2008, and 2007, respectively. Amounts do not include estimates of future Federal and state income taxes.

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Year	Gas (Mcf) *	Oil (bbls) *	Estimated Future Net Revenues	Estimated Future Net Revenues Discounted at 10%
2009	**14,940,000**	**876,000**	**$ 71,863,000**	**$ 40,434,000**
2008	15,525,000	710,000	$ 53,655,000	$ 32,330,000
2007	16,973,000	591,000	$ 101,501,000	$ 62,071,000

* The percentage of total reserves classified as proved developed was approximately 61% in 2009, 67% in 2008, and 76% in 2007.

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 13 to the company s Consolidated Financial Statements.

	Year Ended October 31, 2009	2008	2007
Estimated future net revenues discounted at 10%	$ 40,434,000*	$ 32,330,000*	$ 62,071,000*
Future income tax expense	(15,119,000)	(9,119,000)	(24,967,000)
Effect of the 10% discount factor on future income tax expense	7,285,000	4,408,000	9,697,000
Standardized measure of discounted future net cash flows	$ 32,600,000	$ 27,619,000	$ 46,801,000

* The average price used to calculate estimated future net revenues was $69.24, $62.25 and $86.61 per barrel of oil and $4.49, $3.50 and $5.89 per Mcf of gas as of October 31, 2009, 2008, and 2007, respectively.

Production, Average Sales Prices and Average Production Costs

The company s net production quantities and average price realizations per unit for the indicated years are set forth below. Price realizations include realized derivative gains or losses.

	2009		2008		2007	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Oil (bbls)	**116,000**	**$ 51.46**	56,000	$ 99.28	51,000	$ 60.95

Gas (Mcf)	**1,229,000**	**$**	**6.37**(1)	1,545,000	$	7.40(2)	1,926,000	$	6.78(3)

(1) Included $3.02 Mcf realized natural gas hedging derivative gain.

(2) Includes $0.25 Mcf realized natural gas hedging derivative loss.

(3) Includes $0.99 Mcf realized natural gas hedging derivative gain.

Average production costs, including production taxes, per equivalent Mcf of production (using a six Mcf of gas to one barrel of oil conversion ratio) were $1.71, $2.05 and $1.51 per Mcfe in 2009, 2008, and 2007, respectively.

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Productive Wells and Developed Acreage

Developed acreage at October 31, 2009 totaled 28,000 net and 188,000 gross acres. At October 31, 2009, the company owned working interests in 93 net (339 gross) wells consisting of 70.61 net (265 gross) natural gas wells and 22.21 net (74 gross) oil wells. In addition, the company owned royalty and production payment interests in approximately 1,181 wells, primarily coal bed methane, located in Wyoming. In 2009, no wells were sold or abandoned or acquired.

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,	Royalty Interest Acreage		Working Interest Acreage	
	Gross	Net	Gross	Net
2010	3,300	100	49,100	16,800
2011			86,600	52,500
2012			11,400	7,600
2013			7,800	6,100
2014			1,600	500
Thereafter	3,700	500	3,000	1,900
Held-By-Production	148,100	7,900	16,300	3,500
Total	155,100	8,500	175,400	88,900

In general, royalty interests are non-operated interests which are not burdened by costs of exploration or lease operations, while working interests have operating rights and participate in 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
2009(1)	**25**	**7**	**2**	**12**	**1**	**2**	**1**
2008	32	12	9	11			
2007	24	5	11	7		1	

(1) Of the gross wells drilled in 2009, 3 of the oil wells, 2 of the gas wells and 8 of the dry holes were operated by the company. The remaining wells represent company participations in wells operated by others.

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Net Wells

Year Ended October 31,	Total Net Wells	Exploratory Oil	Exploratory Gas	Exploratory Dry	Development Oil	Development Gas	Development Dry
2009(1)	**12.089**	**3.007**	**0.131**	**7.109**	**0.168**	**1.230**	**0.444**
2008	6.581	1.874	1.886	2.821			
2007	8.591	1.166	4.143	2.700		0.582	

(1) Of the net wells drilled in 2009, 2.550 of the oil wells, 1.230 net gas wells and 6.043 net 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 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. The company believes that this space is adequate for its current needs. The company s current lease expires in April 2011.

As of October 31, 2009, the company had 13 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. As of the date of this Annual Report on Form 10-K, the company has been 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 company believes that a contractual agreement requires that disputes be resolved by arbitration. Although the company believes the allegations are without merit and that the company will ultimately prevail, the ultimate outcome of this lawsuit, or arbitration, cannot be determined at this time.

The company has also 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. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the fourth quarter of 2009.

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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 MarketSM 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.

	2009		2008	
Quarter Ended	**High**	**Low**	**High**	**Low**
January 31	**$ 10.21**	**$ 7.86**	$ 10.37	$ 7.95
April 30	**$ 9.53**	**$ 6.73**	$ 11.36	$ 8.57
July 31	**$ 12.87**	**$ 8.08**	$ 18.04	$ 9.93
October 31	**$ 12.90**	**$ 9.72**	$ 11.06	$ 6.03

At January 4, 2010, the company had 2,321 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 the fiscal year, the company repurchased 196,494 shares of its common stock on the open market at a weighted average price of $9.27. The purchases were made pursuant to a stock repurchase plan announced on September 24, 2008. The plan authorized repurchases up to $2,000,000, and was subsequently expanded to authorize purchases up to $4,000,000. Subsequent to October 31, 2009, and through January 7, 2010, the company has repurchased an additional 36,937 shares, bringing the total shares repurchased to 332,371 at an average price per share of $8.79.

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
Total	295,434	$	8.61	295,434		

Subsequent to October 31, 2009, and through January 7, 2010, the company has repurchased an additional 36,937 shares, bringing the total shares repurchased to 332,371 at an average price per share of $8.79.

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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, 2009 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.

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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, 2009 were derived from the audited financial statements and the accompanying notes to those financial statements.

	Years Ended October 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Audited Financial Information					
Statement of Operations Data:					
Oil and gas sales	**$ 10,067,000**	$ 17,345,000	$ 14,265,000	$ 16,103,000	$ 13,862,000
Oil and gas production expense	**3,260,000**	3,861,000	3,375,000	3,407,000	2,759,000
Depreciation, depletion and amortization	**4,439,000**	3,583,000	3,666,000	3,642,000	2,402,000
Non-cash writedown of oil & gas properties and impairment of long lived assets	**24,653,000**				
General and administrative	**3,250,000**	1,637,000	1,397,000	1,291,000	1,117,000
Income(loss) from operations	**(25,535,000)**	8,264,000	5,827,000	7,763,000	7,584,000
Realized and Unrealized gains(losses) from derivative contracts	**2,079,000**	188,000	1,455,000	1,061,000	(537,000)
Income(loss) before income taxes	**(23,515,000)**	8,153,000	8,075,000	9,436,000	7,156,000
Net income(loss)	**(14,454,000)**	5,993,000	5,760,000	6,836,000	5,153,000
Earnings(loss) per share:					
Basic	**$ (1.40)**	$ 0.62	$ 0.62	$ 0.74	$ 0.57
Diluted	**$ (1.40)**	$ 0.61	$ 0.61	$ 0.72	$ 0.55
Weighted-average shares outstanding(1):					
Basic	**10,326,000**	9,697,000	9,280,000	9,207,000	9,080,000
Diluted	**10,326,000**	9,758,000	9,395,000	9,482,000	9,367,000
Balance Sheet Data:					
Working capital	**13,542,000**	24,160,000	12,511,000	10,073,000	7,697,000
Total assets	**52,552,000**	80,650,000	55,349,000	47,759,000	37,844,000
Long-term obligations:					
Deferred income taxes-net	**2,537,000**	11,117,000	9,204,000	8,039,000	5,978,000
Asset retirement obligation	**1,502,000**	1,338,000	1,016,000	954,000	929,000
Exclusive license agreement obligation			85,000	163,000	233,000
Stockholders equity	**46,056,000**	62,211,000	41,140,000	34,767,000	26,947,000
Unaudited Operating Data					
Production Volumes:					
Oil (Bbls)	**116,000**	56,000	51,000	41,000	37,000
Gas (Mcf)	**1,229,000**	1,545,000	1,926,000	2,176,000	1,830,000
Mcfe	**1,923,000**	1,880,000	2,234,000	2,422,000	2,050,000
Avg. sales price before realized derivative gains & losses:					

Per Bbls	**$**	**51.46**	$	99.28	$	60.95	$	61.14	$	50.90
Per Mcf	**$**	**3.35**	$	7.65	$	5.79	$	6.24	$	6.55
Avg. sales price after realized derivative gains & losses:										
Per Bbls	**$**	**51.46**	$	99.28	$	60.95	$	61.14	$	50.90
Per Mcf	**$**	**6.37**	$	7.40	$	6.78	$	6.11	$	6.16
Reserves((1)										
Oil (Bbls)		**876,000**		710,000		591,000		422,000		386,000
Gas (Mcf)		**14,940,000**		15,525,000		16,973,000		16,005,000		15,516,000
Mcfe		**20,197,000**		19,788,000		20,517,000		18,537,000		17,835,000
Estimated future net revenues	**$**	**71,863,000**	$	53,655,000	$	101,501,000	$	84,861,000	$	136,878,000
Estimated future net revenues discounted at 10%	**$**	**40,434,000**	$	32,330,000	$	62,071,000	$	52,328,000	$	81,209,000

(1) See Footnote 13 to the Consolidated Financial Statements.

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

Operations

Summary During 2008 and 2009, the company s operations were focused on its two core projects drilling in the Mid-Continent and Rocky Mountain areas of the U.S. and application of its Calliope Gas Recovery System. During the past several years, the company has significantly expanded the volume and breadth of its drilling activities by diversifying geographically, scientifically, and in terms of capital, risk and reserve potential. The company has also implemented a program to increase the volume of its Calliope applications by joint venturing with other companies.

These activities are discussed in greater detail below.

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

The company will continue to actively pursue adding reserves through its two core projects in fiscal 2010, and expects these activities to be a reliable source of reserve additions. However, the timing and extent of such activities can be dependent on many factors which are beyond the company s control, including but not limited to the availability of oil field services such as drilling rigs, production equipment and related services, and access to wells for application of the company s patented gas recovery system on low pressure gas wells. The prevailing price of oil and natural gas has a significant effect on demand and, thus, the related cost of such services and wells.

Results of Operations

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 (excluding realized derivative gains and losses). As the oil and gas price/volume table on page 22 shows, total gas price realizations, which reflect realized derivative transactions, decreased 14% to $6.37 per Mcf and oil price realizations decreased to $51.46 per barrel. The net effect of these price realization changes was to decrease total oil and gas sales realizations by $5,200,000 ($9,305,000 decrease without derivative gains and losses). 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.

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The effective tax rate was 38.5% and 26.5% for the 2009 and 2008 periods, respectively. The variation from the statutory rate in 2008 is primarily due to percentage depletion.

In 2008, oil and gas revenues increased 22% to $17,345,000 compared to $14,265,000 in 2007. The increase was due to a 63% increase in oil prices and a 32% increase in gas prices (excluding realized derivative gains and losses) partially offset by a 16% decrease in gas equivalent production. As the oil and gas price/volume table on page 22 shows, total gas price realizations, which reflect realized derivative transactions, increased 9% to $7.40 per Mcf and oil price realizations increased to $99.28 per barrel. The net effect of these price realization changes was to increase oil and gas sales by $3,252,000 (vs. $5,547,000 increase without derivative gains and losses). Realized derivative losses were $1,113,000 in 2008 compared to gains of $1,909,000 in 2007. During the same period, the company s gas equivalent production fell 16% resulting in a decrease in oil and gas sales of $2,467,000. Unrealized derivative gains were $1,301,000 in 2008 compared to unrealized losses of $454,000 in 2007. Investment and other income decreased primarily due to market place declines impact on the company s investments.

In 2008, total costs and expenses rose 7.6% to $9,081,000 compared to $8,438,000 in 2007. Oil and gas production expenses increased 14% due primarily to the addition of new wells and escalating field service costs. General and administrative expenses increased 17% primarily due to increases in salaries and benefits, accounting and professional fees. The effective tax rate was 26.5% and 28.7% for 2008 and 2007, respectively. The variation from statutory rate is primarily due to percentage depletion.

Liquidity and Capital Resources

At October 31, 2009, working capital decreased to $13,542,000, compared to $24,160,000 at October 31, 2008, primarily due to the use of cash for additions to oil and gas properties, other long-term assets and intangible assets. For the year ended October 31, 2009, net cash provided by operating activities was $9,932,000 compared to $12,293,000 for the same period in 2008. The difference is primarily due to decrease in net income of $5,285,000 excluding the non-cash effect of oil and gas property and intangible asset impairment charges, offset by differences in non-cash unrealized gains/losses from derivatives of $2,942,000, differences in non cash gains/losses from short term investments of $438,000, a change in net proceeds from short term investment liquidations of $492,000 and a decrease in other operating assets and liabilities of $1,132,000. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $11,480,000 and $12,528,000 in 2009 and 2008, respectively. Financing activities primarily included the purchase of treasury stock of $1,821,000 and $722,000 in 2009 and 2008, the sale of common stock of $15,095,000 net of transaction costs in 2008, and proceeds and tax benefits from exercise of stock options of $89,000 and $637,000 in 2009 and 2008, respectively.

The company s earnings before interest, taxes, depreciation, depletion and amortization and write-downs of oil and gas properties and impairment losses (EBITDA) was $5,580,000 for the year ended October 31, 2009 and $11,744,000 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:

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	For The Year Ended October 31,		
	2009	**2008**	**2007**
RECONCILIATION OF EBITDA:			
Net Income (Loss)	**$ (14,454,000)**	$ 5,993,000	$ 5,760,000
Add Back(Deduct):			
Interest Expense	**3,000**	8,000	26,000
Income Tax Expense (Benefit)	**(9,061,000)**	2,160,000	2,315,000
Depreciation, Depletion and Amortization Expense	**4,439,000**	3,583,000	3,666,000
Write-Down of oil and natural gas properties and impairment of intangible assets	**24,653,000**		
EBITDA	**$ 5,580,000**	$ 11,744,000	$ 11,767,000

During 2009 the company liquidated the majority of its short term investments in professionally managed limited partnerships which were not publicly traded and had less readily determinable market values. Only $342,000 of these investments remain at October 31, 2009. These investments are anticipated to be entirely liquidated during early fiscal 2010. Other short term investments are directly invested in certificates of deposit and mutual funds.

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, 2009, 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, 2009, 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	61,000	41,000	20,000		
Total	$ 61,000	$ 41,000	$ 20,000	$	$

Impact of Current Credit Markets

As the company exited the fourth quarter of fiscal 2009, oil and natural gas prices remained sharply below their 2008 record levels. In addition, problems in the credit markets, steep stock market declines, financial institution failures and government bail-outs provide evidence of a weakened United States and global economy. As a result of the market turmoil and price decreases, oil and gas companies with high debt levels and lack of liquidity have been and will continue to be negatively impacted. However, the company does not expect to be significantly impacted by these events. The company has no debt and is in a financially strong position due in large part to its historical policy of conservative balance sheet management. The company anticipates its cash on hand and operating cash flow will adequately fund planned capital expenditures and other capital uses over the near-term, however, the company is not opposed to taking on reasonable debt to finance opportunities which it believes are in the company s best long term interest.

Off-Balance Sheet Arrangements

The company has no off-balance sheet arrangements at October 31, 2009.

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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 indicated years ended October 31 are set forth below. Price realizations include realized hedging gains and losses.

	2009	2008	2007
Price Realization			
Oil			
Net wellhead price received (per Bbl)	**$ 51.46**	$ 99.28	$ 60.95
Effects of derivative gains (losses) (per Bbl)			
Net price realization (per Bbl)	**$ 51.46**	$ 99.28	$ 60.95
% Change	**(48)%**	63%	0%
Natural Gas			
Net wellhead price received (per Mcf)	**$ 3.35**	$ 7.65	$ 5.79
Effects of derivative gains (losses) (per Mcf) (1)	**3.02**	(0.25)	0.99
Net price realization (per Mcf)	**$ 6.37**	$ 7.40	$ 6.78
% Change	**(14)%**	9%	11%

	2009	2008	2007
Total Sales Volumes			
Oil (Bbl)	**116,000**	**56,000**	51,000
% Change	**108%**	**9%**	24%
Natural Gas (Mcf)	**1,229,000**	**1,545,000**	1,926,000
% Change	**(21)%**	**(20)%**	(11)%
Total equivalent production (Mcfe)	**1,923,000**	**1,880,000**	2,234,000
% Change	**2%**	**(16)%**	(8)%

(1) Effects of realized gains (losses) on natural gas derivative contracts.

Although product prices are key to the company s ability to operate profitably and to budget capital expenditures, they are beyond the company s control and are difficult to predict. Since 1991, the company has periodically hedged the price of a portion of its estimated natural gas production when the potential for significant downward price movement is anticipated. Derivative transactions typically take the form of forward short positions on the NYMEX futures market, and are closed by purchasing offsetting positions.

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.

Open derivative contracts at October 31, 2009 are indexed to the NYMEX and are represented by short positions and offsetting long positions. The company also held basis differential hedges for NYMEX vs. Panhandle Eastern Pipeline basis differentials. Actual price realizations in the company s principal areas of operations (primarily Oklahoma) are currently 2% below NYMEX prices primarily due to basis differentials. However, regional weather conditions and other economic factors frequently result in substantially higher basis differentials which have historically averaged in the 15% range.

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 $5,900,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the company s bank, and prohibits funded debt in excess of $500,000. The line expires November 15, 2010.

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Oil and Gas Activities

Capital Spending. Capital spending in 2009 totaled $18,184,000, consisting primarily of additions to oil and gas properties. In November, 2008, the company purchased all of the Calliope Gas Recovery System patents and all of the remaining third party right, title and interest in the Calliope technology. In addition, the company purchased all of the patents for its new Tractor Seal fluid lift technology together with all third party right, title and interest 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 located on the northern shelf of the Anadarko Basin of Oklahoma and North Texas 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 area. However, in recent years the company has diversified its drilling activities into other regions and has deemphasized drilling for natural gas in favor of drilling for crude oil reserves. Continued drilling on the company s Oklahoma and North Texas 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 central Kansas, North Dakota s Williston Basin, and South Texas. Compared to drilling in Oklahoma, the North Dakota and South Texas projects involve higher costs and greater risks but significantly higher per well reserve potential. In contrast, drilling in central Kansas is less expensive than the company s Oklahoma drilling projects while still yielding excellent economics.

In central Kansas, the company owns interests in approximately 140,000 gross acres and 77,000 net acres and it is continuing to expand its acreage position. At October 31, 2009, the company has participated in drilling 44 wells on its acreage, of which 43% 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. The company owns working interests in the existing prospects ranging from 12.5% to 85%. The company s north-central Kansas drilling activities provide diversification to the company s drilling program geographically and scientifically 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 Northern Anadarko Basin, North Dakota Bakken, and South Texas projects, is relatively low cost, low risk, and exclusively targets oil reserves.

In North Dakota s Bakken oil shale play, the company has assembled approximately 7,600 gross 5,675 net acres on the Fort Berthold Indian Reservation south and west of Parshall Field. The acreage consist of approximately 33 drilling locations based on 640 acre spacing units and 13 locations based on 1,280 acre 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 Three Forks shales. Breakthroughs in precision horizontal drilling and multi-stage, high pressure fracture stimulations have made the Bakken shale a very active resource play which is being actively developed by a significant number of companies, including large independents and majors. The U.S. Geological Survey recently estimated that the Bakken contains around 4.0 billion barrels of undiscovered oil. 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. Drilling is complete on the first Bakken horizontal well in which the company owns an interest and the well is currently awaiting completion which has been delayed due to cold weather and is now expected to commence in

February 2010. The horizontal leg of the well is approximately 9,200 feet and will be completed in multiple stages. Credo owns a 10% working interest. Work is currently under way in preparation for drilling two to three additional wells on company acreage.

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The South Texas project is 3-D seismic driven with well depths ranging from 10,000 to 17,000 feet. The most significant well drilled to date tested the Deep Wilcox formation on the Gemini Prospect and resulted in a dry hole. The 17,000-foot well confirmed the seismic interpretation and found porous sand. However, the sand was water wet and the well was plugged and abandoned. The company received approximately $1,300,000 of cash for the multiple prospect package and retained an 11.25% carried interest in the test well. The prospect package sold consists of two additional Deep Wilcox prospects located to the north of Gemini Prospect. These two prospects are structurally different and unique compared to the Gemini Prospect. Those prospects are being further evaluated, and if drilled, the company will have the same 11.25% carried interest in the next well as it did in the Gemini Prospect test well. This project is highly dependent on natural gas prices and is currently on hold due to low natural gas prices.

The company owns the patents covering Calliope and 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 more than 1,000 wells that meet its general criteria for Calliope candidate wells and thousands more that will meet its general Calliope 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 Chester, Cotton Valley, Edwards, Hart, Hunton, Morrow, Nodosaria, Red Fork and Springer reservoirs. At the time Calliope was installed, 14 of the wells were dead, nine were uneconomic and two were marginal. There are 14 non-experimental Calliope wells. As a group, those wells were producing a total of 88 thousand cubic feet of gas per day at the time Calliope was installed. Since Calliope was installed, those wells have produced 5.4 billion cubic feet of gas and they now have estimated ultimate (8/8ths) Calliope reserves totaling 7.0 billion cubic feet of gas. Ten 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.

On November 6, 2008 the company purchased all of the patents underlying Calliope, all of the related third party interests in future installations of the technology and 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. During fiscal 2009, a joint venture agreement for a pilot project was completed with a large independent and joint venture discussions are underway with several companies, both large and small.

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.

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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. A change in proved reserves without a corresponding change in capitalized costs will cause the depletion rate to increase or decrease.

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

The capitalized costs in the full cost pool are subject to a quarterly ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and natural gas reserves discounted at 10 percent plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the company will record a write-down to the extent of such excess as a non-cash charge to earnings, unless the company considered price increases subsequent to the quarterly balance sheet date which may reduce or eliminate a write-down. 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 prices in effect as of the last day of the test period be used and held constant. The resulting valuation is a snapshot as of that day and, thus, is generally not indicative of a true fair value that would be placed on the company s reserves by the company or by an independent third party. Therefore, the future net revenues associated with the estimated proved reserves are not based on the company s assessment of future prices or costs, but rather are based on prices and costs in effect as of the end the test period.

Oil and Gas Reserves. The determination of depreciation and depletion expense as well as ceiling test write-downs related to the recorded value of the company s oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves. Oil and

natural gas reserves include proved reserves that represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their values, including many factors beyond the company s control. Accordingly, reserve estimates are often different from the quantities of oil and natural gas ultimately recovered and the corresponding lifting costs associated with the recovery of these reserves are often different than the estimated costs.

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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 liquid lift system is generally installed on mature wells. As such, they contain older down-hole equipment that is more subject to failure than new equipment. The failure of such equipment, particularly casing, can result in complete loss of a well. Historically, performance of the company s wells has not caused significant revisions in its proved reserves.

One measure of the life of the company s proved reserves can be calculated by dividing proved reserves at fiscal year end 2009 by production for fiscal year 2009. This measure yields an average reserve life of 10.5 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.

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.

Recent Accounting Pronouncements

In May 2009, the FASB issued authoritative guidance that provides general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This topic was previously addressed only in auditing literature. This guidance is similar to the existing auditing guidance with some exceptions that are not intended to result in significant changes to practice. Entities are now required to disclose the date through which subsequent events have been evaluated, with such date being the date the financial statements were issued or available to be issued. This guidance was effective on a prospective basis for interim or annual reporting periods ending after June 15, 2009. Accordingly, the company adopted this guidance for the quarter ended July 31, 2009. There was no impact on the company s financial position or results of operations as a result of the adoption.

In April 2009, the FASB issued authoritative guidance that requires the disclosure of the fair value, together with the carrying amount, of financial instruments, regardless of whether they are recognized at fair value in the statement of financial position, for interim reporting periods of publicly traded companies as well as in annual financial statements. This guidance was effective for interim reporting periods ending after June 15, 2009, with earlier adoption permitted for periods ending after March 15, 2009. The company adopted this guidance for the quarter ended July 31, 2009. As this guidance requires only additional disclosures, there was no impact on the company s financial position or results of operations as a result of the adoption.

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 will: 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

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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 is currently evaluating the impact that the adoption of these amendments will have on the company s financial position, results of operations, and disclosures. In September 2009, the FASB issued proposed authoritative guidance to align oil and gas reserve estimation and disclosures required for accounting and reporting with the new SEC reserve disclosure requirements discussed above. The proposed guidance would be effective for December 31, 2009 reporting on a prospective basis. Comments on this exposure draft were due in October 2009, with final guidance expected to be issued soon.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The company manages exposure to commodity price fluctuations by periodically hedging a portion of estimated natural gas production through the use of derivatives, typically forward short positions in the NYMEX futures market. At October 31, 2009 the company held open derivative contracts representing short sales positions for 420,000 MMBtus at NYMEX basis prices ranging from $4.60 to $7.27 and covering the production months of November 2009 through December 2010. The company also held open derivative contracts representing long positions that offset the short sales. The long position contracts are at NYMEX basis prices ranging from $4.38 to $5.83. The open derivative contracts net to zero volume but will result in hedging gains of $179,000 as the contracts expire.

At October 31, 2009 the company also held basis differential hedges on 540,000 MMBtus with NYMEX vs. Panhandle Eastern Pipeline basis differentials ranging from $0.16 to $0.47 and covering the production months of November 2009 through December 2010.

See Management s Discussion and Analysis of Financial Condition and Results of Operations Product Prices and Production for more information on the company s hedging activities.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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CONSOLIDATED BALANCE SHEETS

October 31, 2009 and 2008

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2009	2008
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 12,348,000**	$ 22,332,000
Short-term investments	**635,000**	3,044,000
Receivables:		
Trade	**487,000**	995,000
Accrued oil and gas sales	**1,566,000**	1,733,000
Derivative assets	**104,000**	1,745,000
Other current assets	**859,000**	205,000
Total current assets	**15,999,000**	30,054,000
Long-term assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	**7,363,000**	12,280,000
Evaluated oil and gas properties	**76,127,000**	59,730,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	**(53,211,000)**	(25,554,000)
Net oil and gas properties	**30,279,000**	46,456,000
Intangible assets, net of accumulated amortization of $436,000 in 2009 and $595,000 in 2008	**4,013,000**	1,079,000
Compressor and tubular inventory to be used in development of oil and gas properties	**1,865,000**	2,592,000
Other, net	**396,000**	379,000
Total assets	**$ 52,552,000**	$ 80,560,000
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	**$ 407,000**	$ 3,857,000
Revenue distribution payable	**653,000**	982,000
Accrued compensation	**948,000**	198,000
Other accrued liabilities	**394,000**	733,000
Income taxes payable	**55,000**	124,000
Total current liabilities	**2,457,000**	5,894,000
Long-term liabilities:		
Deferred income taxes, net	**2,537,000**	11,117,000
Asset retirement obligation	**1,502,000**	1,338,000
Total liabilities	**6,496,000**	18,349,000
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	**31,472,000**	31,352,000

Treasury stock, at cost, 419,000 shares in 2009, and 223,000 shares in 2008		**(2,803,000)**		(982,000)
Retained earnings		**16,321,000**		30,775,000
Total stockholders equity		**46,056,000**		62,211,000
Total liabilities and stockholders equity	**$**	**52,552,000**	$	80,560,000

See accompanying notes to consolidated financial statements.

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CONSOLIDATED STATEMENTS OF OPERATIONS

For the Three Years Ended October 31, 2009

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2009	2008	2007
Oil sales	**$ 5,953,000**	$ 5,530,000	$ 3,121,000
Gas sales	**4,114,000**	11,815,000	11,144,000
	10,067,000	17,345,000	14,265,000
Costs and expenses:			
Oil and gas production	**3,260,000**	3,861,000	3,375,000
Depreciation, depletion and amortization	**4,439,000**	3,583,000	3,666,000
Write-down of oil and natural gas properties (Note 3) and impairment of long lived assets (Note 8)	**24,653,000**		
General and administrative	**3,250,000**	1,637,000	1,397,000
	35,602,000	9,081,000	8,438,000
Income(loss) from operations	**(25,535,000)**	8,264,000	5,827,000
Other income and (expense)			
Realized and Unrealized gains (losses) from derivative contracts	**2,079,000**	188,000	1,455,000
Investment and other income (loss)	**(59,000)**	(299,000)	793,000
	2,020,000	(111,000)	2,248,000
Income(loss) before income taxes	**(23,515,000)**	8,153,000	8,076,000
Income taxes	**9,061,000**	(2,160,000)	(2,315,000)
Net income(loss)	**$ (14,454,000)**	$ 5,993,000	$ 5,760,000
Earnings(loss) per share of Common Stock-Basic	**$ (1.40)**	$ .62	$ .62
Earnings(loss) per share of Common Stock-Diluted	**$ (1.40)**	$ .61	$ .61
Weighted average number of shares of common stock and dilutive securities:			
Basic	**10,326,000**	9,697,000	9,280,000
Diluted	**10,326,000**	9,758,000	9,395,000

See accompanying notes to consolidated financial statements.

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

For the Three Years Ended October 31, 2009

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	Common Stock		Capital In Excess Of	Treasury	Retained	Total Stockholders
	Shares	Amount	Par Value	Stock	Earnings	Equity
Balance, October 31, 2006	9,510,000	$ 951,000	$ 14,794,000	$	$ 19,022,000	$ 34,767,000
Comprehensive income (loss):						
Net income					5,760,000	5,760,000
Purchase of treasury stock				(506,000)		(506,000)
Exercise of common stock options			368,000			368,000
Compensation expense related to stock options			153,000			153,000
Tax benefit from exercise of stock options			598,000			598,000
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

See accompanying notes to consolidated financial statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Three Years Ended October 31, 2009

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2009	2008	2007
Cash flows from operating activities:			
Net income(loss)	**$ (14,454,000)**	$ 5,993,000	$ 5,760,000
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	**4,439,000**	3,583,000	3,666,000
ARO liability accretion	**77,000**	51,000	36,000
Unrealized (gains) losses from derivatives	**1,641,000**	(1,301,000)	454,000
Deferred income taxes	**(8,580,000)**	1,913,000	1,763,000
(Gain)loss on short-term investments	**180,000**	618,000	(603,000)
Compensation expense related to stock options granted	**31,000**	68,000	153,000
Other		63,000	26,000
Changes in operating assets and liabilities:			
Proceeds from short-term investments	**2,229,000**	2,721,000	1,544,000
Purchase of short-term investments			(1,700,000)
Trade receivables	**508,000**	(393,000)	316,000
Accrued oil and gas sales	**167,000**	(86,000)	175,000
Other current assets	**(654,000)**	(150,000)	16,000
Accounts payable and accrued liabilities	**(236,000)**	(477,000)	(192,000)
Income taxes payable	**(69,000)**	(310,000)	260,000
Net cash provided by operating activities	**9,932,000**	12,293,000	11,674,000
Cash flows from investing activities:			
Additions to oil and gas properties	**(13,719,000)**	(9,544,000)	(9,144,000)
Proceeds from sale of oil and gas properties			310,000
Changes in other long-term assets	**(65,000)**	(1,652,000)	84,000
Purchase of intangible assets	**(4,400,000)**	(975,000)	
Net cash used in investing activities	**(18,184,000)**	(12,171,000)	(8,750,000)
Cash flows from financing activities:			
Sale of common stock		15,095,000	
Proceeds and the benefit from exercise of stock options	**89,000**	637,000	368,000
Purchase of treasury stock	**(1,821,000)**	(722,000)	(506,000)
Principal payment on exclusive license obligation		(85,000)	(78,000)
Net cash provided (used) by financing activities	**(1,732,000)**	14,925,000	(216,000)
Increase (decrease) in cash and cash equivalents	**(9,984,000)**	15,047,000	2,708,000
Cash and cash equivalents:			

Beginning of year		**22,332,000**		7,285,000	4,577,000
End of year	**$**	**12,348,000**	$	22,332,000	$ 7,285,000
Supplemental Cash Flow Information:					
Cash paid during the period for income taxes	**$**		$	447,000	$ 371,000
Additions to oil & gas properties included in current liabilities	**$**	**74,000**	$	3,127,000	

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

See accompanying notes to consolidated financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

October 31, 2009

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

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 which were not publicly traded and had less readily determinable market values. Only $342,000 of these investments remain at October 31, 2009. These investments are anticipated to be entirely liquidated during early fiscal 2010. 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 JIB 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, 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 recorded in the month production is delivered to the purchaser at which time title changes hands (the sales method). 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.

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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

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.

Intangible Assets

Intangible assets are carried at cost less accumulated amortization. Amortization is calculated on a ratable basis over the expected useful life of the asset. Intangible assets are periodically reviewed for indications of impairment and if impairment has occurred, the asset is written down to its expected realizable value.

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:

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	October 31, 2009	2008
Beginning asset retirement obligation	**$ 1,338,000**	$ 1,016,000
Accretion expense	**77,000**	51,000
Obligations incurred	**87,000**	259,000
Obligations settled	**1,000**	
Change in estimate	**(1,000)**	12,000
Ending asset retirement obligation	**$ 1,502,000**	$ 1,338,000

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.

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.

Natural Gas Derivatives

The company periodically uses derivatives as economic hedges of the price of a portion of its estimated natural gas production when the potential for significant downward price movement is anticipated. These transactions typically take the form of forward short positions based upon the NYMEX futures market, 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.

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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. Total potential dilutive shares based on options outstanding at October 31, 2009 were 30,000.

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

	Year Ended October 31,								
	2009			2008			2007		
	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	**$ (14,454,000)**	**10,326,000**	**$ (1.40)**	$ 5,993,000	9,697,000	$ .62	$ 5,760,000	9,280,000	$ .62
Effect of dilutive shares of common stock from stock options			( )		61,000	(.01)		115,000	(.01)
Earnings(loss) per share-Diluted	**$ (14,454,000)**	**10,326,000**	**$ (1.40)**	$ 5,993,000	9,758,000	$ .61	$ 5,760,000	9,395,000	$ .61

The company s outstanding options were not included in the calculations of diluted earnings (loss) per share for the year ended October 31, 2009 as their inclusion would have an antidilutive effect.

Accrued Compensation

In 2009 accrued salary and bonus includes $414,000 as a one time retirement payment for the company s retiring Chief Executive Officer.

SUBSEQUENT EVENTS

Management has evaluated events and transactions occurring after the balance sheet date through January 7, 2010, the date that financial statements were issued.

Recent Accounting Pronouncements

In May 2009, the FASB issued authoritative guidance that provides general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This topic was previously addressed only in auditing literature. This guidance is similar to the existing auditing guidance with some exceptions that are not intended to result in significant changes to practice. Entities are now required to disclose the date through which subsequent events have been evaluated, with such date being the date the financial statements were issued or available to be issued. This guidance was effective on a prospective basis for interim or

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annual reporting periods ending after June 15, 2009. Accordingly, the company adopted this guidance for the quarter ended July 31, 2009. There was no impact on the company s financial position or results of operations as a result of the adoption.

In April 2009, the FASB issued authoritative guidance that requires the disclosure of the fair value, together with the carrying amount, of financial instruments, regardless of whether they are recognized at fair value in the statement of financial position. The company adopted this guidance for the year ended October 31, 2009. As this guidance requires only additional disclosures, there was no impact on the company s financial position or results of operations as a result of the adoption.

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 will: 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 is currently evaluating the impact that the adoption of these amendments will have on the company s financial position, results of operations, and disclosures. In September 2009, the FASB issued proposed authoritative guidance to align oil and gas reserve estimation and disclosures required for accounting and reporting with the new SEC reserve disclosure requirements discussed above. The proposed guidance would be effective for December 31, 2009 reporting on a prospective basis. Comments on this exposure draft were due in October 2009, with final guidance expected to be issued soon.

(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, 2009, common shares issued are 10,660,000, common shares held in treasury are 419,000 and common shares outstanding are 10,241,000. 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.

The Purchase Agreement contains a standstill provision that prohibits RCH from acquiring any additional shares of the company s stock for a period of two years without the consent of the company.

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.

During 2007, the company entered into a joint venture agreement with RCH Energy Opportunity

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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, 2009, 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. 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, 2009, the company has acquired 295,434 shares under the program, at an aggregate cost of $2,544,000.

Subsequent to October 31, 2009, and through January 7, 2010, the company has repurchased an additional 36,937 shares, bringing the total shares repurchased to 332,371 at an average price per share of $8.80.

(3) OIL AND NATURAL GAS PROPERTIES

Depreciation, depletion and amortization of oil and natural gas properties for the fiscal years ended October 31, 2009 and 2008 were $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 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. 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, 2009 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 last day of the test period be used and held constant. The resulting valuation is a snapshot as of that day and, thus, is generally not indicative of a true fair value that would be placed on the company s reserves by the company or by an independent third party. Therefore, the future net revenues associated with the estimated proved reserves are not based on the company s assessment of future prices or costs, but rather are based on prices and costs in effect as of the end of the test period.

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(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, 2009, 2008 and 2007.

	NUMBER OF SHARES	WEIGHTED AVERAGE EXERCISE PRICE	AGGREGATE INTRINSIC VALUE(1)	NUMBER OF SHARES EXERCISABLE
Outstanding at October 31, 2006	315,002	$ 5.52	$ 2,363,000	266,939
Granted at fair value	40,000	12.78		
Exercised	(84,187)	4.39	704,000	
Cancelled	(564)	5.93		
Outstanding at October 31, 2007	270,251	6.94	875,000	236,918
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
Cancelled	(53,706)	14.31		
Outstanding at October 31, 2009	179,063	7.46	530,000	169,063

(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.

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 resulted due to an unusual event related to the recently issued options, and the short period that the options were outstanding minimized any effect. Compensation expense related to stock options included in General and Administrative Expense for the years ended October 31, 2009, 2008 and 2007 are $31,000, $68,000 and $153,000, respectively. The estimated unrecognized compensation cost from unvested options as of October 31, 2009 was approximately $33,000, which is expected to be recognized over an average period of 1.1 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 non-director 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 2009, 2008 and 2007 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.

	2009	2008	2007
Expected life of options	N/A - No grants in 2009	5 years	2.5 years
Risk free interest rates		2.93%	4.58%
Estimated volatility		49.41%	50.84%
Dividend yield		0.00%	0.00%
Weighted average fair market value of options granted during the year		$ 3.15	$ 4.47

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The following table summarizes information about options outstanding at October 31, 2009.

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	139,063	3.6	$ 5.93	$ 530,000	139,063	5.93	530,000
12.78	40,000	7.1	12.78		30,000	12.78	
$ 5.93 - $12.79	179,063	4.4	$ 7.46	$ 530,000	169,063	7.15	$ 530,000

(5) NATURAL GAS DERIVATIVES

The company is exposed to certain commodity price risks relating to its ongoing operations.

The company has elected not to designate its commodity derivatives as cash flow hedges for accounting purposes. Accordingly, such contracts are recorded at fair value on the balance sheet and changes in fair value are recorded in the statement of operations as they occur. The company had realized derivative gains of $3,720,000 in 2009, losses of $1,113,000 in 2008, and gains of $1,909,000 in 2007. The company had unrealized losses on derivative contracts in 2009 of $1,641,000, gains of $1,301,000 in 2008 and losses of $454,000 in 2007. At October 31, 2009 the company held open derivative contracts representing short sales positions for 420,000 MMBtus at NYMEX basis prices ranging from $4.60 to $7.27 and covering the production months of November 2009 through December 2010. The company also held open derivative contracts with the same counterparty representing long positions that offset the short sales. The long position contracts are at NYMEX basis prices ranging from $4.38 to $5.83. These positions are presented net due to the contractual netting provisions with the counterparty. The open derivative contracts net to zero volume but will result in hedging gains of $179,000 as the contracts expire.

At October 31, 2009 the company also held basis differential hedges on 540,000 MMBtus with NYMEX vs. Panhandle Eastern Pipeline basis differentials ranging from $0.16 to $0.47 and covering the production months of November 2009 through December 2010.

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, 2009	
	Balance Sheet Location	Fair Value
Natural Gas Forward Short and Long Positions and Basis Swaps	Derivative Asset	$ 104,000

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, 2009
Natural Gas Forward Short and Long Positions and Basis Swaps	Other Income and (Expense)	$ 2,079,000

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 $5,900,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the company to maintain $3,000,000 in cash or short term investments, none of which are required to be maintained at the company s bank, and prohibits funded debt in excess of $500,000. The line expires November 15, 2010.

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Subsequent to October 31, 2009, the company entered into natural gas short swap derivative contracts for 30,000 Mmbtu s per month at a weighted average price of $5.41 per Mmbtu. The contracts cover the production months of January through September 2010.

(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, 2009 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 2006 and 2008 Federal and 2006 through 2008 state tax returns, except Colorado, in which the 2005 tax year also remains open.

At October 31, 2009 the company had $2,225,000 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,		
	2009	**2008**	**2007**
Current	**$ (481,000)**	$ 247,000	$ 1,150,000
Deferred	**(8,580,000)**	1,913,000	1,165,000
Total income tax expense	**$ (9,061,000)**	$ 2,160,000	$ 2,315,000

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

	Years Ended October 31,		
	2009	**2008**	**2007**
Federal taxes at statutory rate	**$ (8,216,000)**	$ 2,853,000	$ 2,826,000
Graduated rates	**244,000**	(56,000)	(64,000)
State income taxes and other	**(742,000)**	210,000	214,000

Percentage depletion	**(347,000)**	(847,000)		(661,000)
	$ (9,061,000)	$ 2,160,000	$	2,315,000

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The principal sources of temporary differences resulting in deferred tax assets and liabilities at October 31, 2009 and 2008 are as follows:

	October 31, 2009	2008
Deferred tax assets:		
Percentage depletion carryforward	**$ 756,000**	$ 419,000
Intangible assets	**282,000**	
Total deferred tax assets	**1,038,000**	419,000
Deferred tax liabilities:		
Oil and gas assets	**(3,002,000)**	(9,706,000)
Derivative instruments	**(32,000)**	(590,000)
State taxes	**(176,000)**	(871,000)
Other	**(365,000)**	(369,000)
Total deferred tax liabilities	**(3,575,000)**	(11,536,000)
Net deferred tax liability	**$ (2,537,000)**	$ (11,117,000)

(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, 2009:

	As of October 31, 2009			
	Level 1	Level 2	Level 3	Total
	(in thousands)			
Asset:				
Short-term investments	$ 293	$	$ 342	$ 635
Derivative assets (current)	$	$ 104	$	$ 104

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

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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, 2009:

	For the Year Ended October 31, 2009 (in thousands)
Balance as of October 31, 2008 (1)	$ 2,764
Total gains or losses (realized or unrealized) included in earnings (2)	(250)
Redemptions	(2,172)
Balance as of October 31, 2009	$ 342

(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

On November 6, 2008 the company purchased all of the patents underlying the Calliope Gas Recovery Technology, all of the related third party interests in future installations of the technology and patents covering a new fluid lift technology for shallow wells known as Tractor Seal for $4,449,000. The patents are being amortized on a straight line basis over the remaining weighted average lives of 10.4 years.

	October 31, 2008		October 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets:				
Calliope intangible assets	$ 1,674,000	$ 595,000	$ 4,449,000	$ 436,000
Aggregate amortization expense:				
For the years ended October 31, 2008 and 2009		$ 94,000		$ 436,000
Estimated future amortization expense:				
For the year ended October 31, 2010				$ 436,000
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
Thereafter		2,269,000
Total	$	4,013,000

In July 2008, the company acquired the third party rights related to certain future Calliope installations for $975,000. Those third party rights would have resulted principally from Calliope installations through certain joint ventures between the company and other natural gas producing companies.

As a result of the natural gas market at January 31, 2009, the company believed it to be more likely than not that the formation of joint ventures for the installation of Calliope technology that would have been subject to these third party rights would not occur within the foreseeable future. Based on that assumption, and in accordance with FASB authoritative guidance, the company determined that the sum of the undiscounted value of cash flows to be derived from future installations of Calliope technology resulting from joint ventures was minimal. Accordingly, the company recorded an impairment loss of $927,000 for the quarter ended January 31, 2009.

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(9) COMPRESSOR AND TUBULAR INVENTORY

Compressor and tubular inventory are finished goods, recorded at cost, which are expected to be used in the future development of 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 2009, 2008 and 2007 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 $107,000 in 2009, $78,000 in 2008, and $75,000 in 2007. The company has no capital leases and no other operating lease commitments.

The company has been 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 company believes that a contractual agreement requires that disputes be resolved by arbitration. Although the company believes the allegations are without merit and that the company will ultimately prevail, the ultimate outcome of this lawsuit, or arbitration, cannot be determined at this time.

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) RESTATEMENT OF PRIOR YEARS

In connection with preparing its quarterly report for third quarter 2008, management of the company and the Audit Committee of its Board of Directors determined that the contemporaneous formal documentation it had historically prepared to support its initial hedge designations in connection with the company s natural gas hedging program did not meet the technical requirements to qualify for cash flow hedge accounting treatment in accordance with SFAS 133. The primary reason for this determination was that the formal hedge documentation lacked specificity of the hedged items and therefore, the cash flow designations failed to meet hedge documentation requirements for cash flow hedge accounting treatment. Consequently, the unrealized gain or loss should have been recorded in the consolidated statements of operations as a component of income before income taxes. Under the cash flow accounting treatment used by the company, the fair values of the hedge contracts was recognized in the consolidated balance sheets with the resulting unrealized gain or loss, net of income taxes, recorded initially in accumulated other comprehensive income and later reclassified through earnings when the hedged production affected earnings.

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On Form 10-K/A, filed September 15, 2008, the company restated its consolidated financial statements for fiscal years ended October 31, 2005, 2006 and 2007. Unrealized gains and losses from derivative contracts were reclassified from Other Comprehensive Income to a separate line item on the Statement of Operations, and realized gains and losses on derivative contracts were reclassified from Oil and Gas Sales to a separate line item on the Statement of Operations. There was no effect in any period on overall cash flows, total assets, total liabilities or total stockholders equity. For the three years ended October 31, 2007, the cumulative effect of the restatement was to increase net income by $756,000 and to increase diluted income per share by $.07. The restatement did not have any impact on any of the company s financial covenants under its line of credit.

(13) SUPPLEMENTARY OIL AND GAS INFORMATION

Capitalized Costs

	October 31,		
	2009	**2008**	**2007**
Unevaluated properties not being amortized	**$ 7,363,000**	$ 12,280,000	$ 7,791,000
Properties being amortized	**76,127,000**	59,730,000	51,691,000
Accumulated depreciation, depletion and amortization	**(53,211,000)**	(25,554,000)	(22,108,000)
Total capitalized costs	**$ 30,279,000**	$ 46,456,000	$ 37,374,000

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, 2009:

Net Costs Incurred During Years Ended:	**Total Unevaluated Properties**
October 31, 2009	$ 4,063,000
October 31, 2008	3,146,000
October 31, 2007 and prior	154,000
	$ 7,363,000

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,		
	2009	**2008**	**2007**
Property acquisition costs net of divestiture proceeds:			
Proved	**$**	$ 442,000	$ 82,000
Unproved	**4,364,000**	6,539,000	2,106,000
Exploration costs	**4,826,000**	4,057,000	3,368,000
Development costs	**2,203,000**	1,219,000	3,252,000
Total before asset retirement obligation	**$ 11,393,000**	$ 12,257,000	$ 8,808,000
Total including asset retirement obligation	**$ 11,480,000**	$ 12,528,000	$ 8,834,000

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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 28% in 2009, 49% in 2008 and 40% in 2007, Coffeeville Resources 37% in 2009.

Oil and Gas Reserve Data (Unaudited)

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

In 2007 McCartney Engineering, Inc., an independent petroleum engineering firm, estimated proved reserves for the company s properties which represented 64% of the total estimated future value of estimated reserves.

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. Estimated values of proved reserves were computed by applying prices in effect at October 31 of the indicated year. The average price used was $69.24, $62.25 and $86.61 per barrel for oil and $4.49, $3.50 and $5.89 per Mcf for gas in 2009, 2008 and 2007, respectively. Estimated future costs were calculated assuming continuation of costs and economic conditions at the reporting date.

The company s reserves, and reserve values, are concentrated in 64 properties (Significant Properties). Some of the Significant Properties are individual wells and others are multi-well properties. At October 31, 2009, the Significant Properties represent 22% 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 16% of the number of Significant Properties and represent 14% of the discounted reserve value of such properties. Reserve additions in 2009 comprises 8% of the Significant Properties and represent 14% 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 liquid lift system is generally installed on mature wells. As such, they contain older down-hole equipment that is more subject to failure than new equipment. The failure of such equipment, particularly casing, can result in complete loss of a well. Historically, performance of the company s wells has not caused significant revisions in its proved reserves.

One measure of the life of the company s proved reserves can be calculated by dividing proved reserves at fiscal year end 2009 by production for fiscal year 2009. This measure yields an average reserve life of 10.5 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.

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

	2009		2008		2007	
	Gas(Mcf)	Oil(bbls)	Gas(Mcf)	Oil(bbls)	Gas(Mcf)	Oil(bbls)
Proved reserves:						
Balance, Beginning of year	**15,525,000**	**710,000**	16,973,000	591,000	16,005,000	422,000
Revisions of previous estimates	**247,000**	**(1,000)**	(4,206,000)	(82,000)	(548,000)	52,000
Extensions and discoveries	**381,000**	**283,000**	3,935,000	248,000	3,442,000	168,000
Purchases of reserves in place	**16,000**		368,000	9,000		
Sales of reserves in place						
Production	**(1,229,000)**	**(116,000)**	(1,545,000)	(56,000)	(1,926,000)	(51,000)
Balance, October 31	**14,940,000**	**876,000**	15,525,000	710,000	16,973,000	591,000
Proved developed reserves:						
Beginning of year	**10,621,000**	**449,000**	12,890,000	458,000	13,683,000	397,000
End of year	**9,633,000**	**454,000**	10,621,000	449,000	12,890,000	458,000

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

	2009	2008	2007
Future cash inflows	**$ 127,731,000**	$ 98,560,000	$ 151,169,000
Future production and development costs	**(55,868,000)**	(44,905,000)	(49,667,000)
Future income tax expense	**(15,119,000)**	(9,119,000)	(24,967,000)
Future net cash flows	**56,744,000**	44,536,000	76,535,000
10% discount factor	**(24,144,000)**	(16,917,000)	(29,734,000)
Standardized measure of discounted future net cash flows	**$ 32,600,000**	$ 27,619,000	$ 46,801,000

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.

	2009	2008	2007
Balance at beginning of year	**$ 27,619,000**	$ 46,801,000	$ 39,751,000
Sales of oil and gas produced, net of production costs	**(6,807,000)**	(13,484,000)	(12,800,000)
Net changes in prices and production costs	**10,670,000**	(17,290,000)	3,233,000
Extensions and discoveries	**5,231,000**	11,134,000	16,658,000
Changes in future development costs	**(1,533,000)**	(2,485,000)	(12,000)
Previously estimated development costs incurred during the period	**1,499,000**	1,506,000	932,000
Revisions of previous quantity estimates, timing, and other	**(3,670,000)**	(10,116,000)	(2,355,000)
Purchases of reserves in place	**34,000**	866,000	
Sales of reserves in place			
Accretion of discount	**2,679,000**	5,811,000	3,975,000
Net change in income taxes	**(3,122,000)**	4,876,000	(2,581,000)
Balance, October 31	**$ 32,600,000**	$ 27,619,000	$ 46,801,000

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(14) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following is a tabulation of the company s unaudited quarterly operating results for fiscal 2007, 2008 and 2009.

	Oil & Gas Sales	Income(Loss) Before Income Taxes	Net Income(Loss)	Basic Earnings (Loss) Per Share	Diluted Earnings (Loss) Per Share
Fiscal 2007:					
First Quarter	$ 3,412,000	$ 1,529,000	$ 1,093,000	$ 0.12	$ 0.12
Second Quarter	4,095,000	2,108,000	1,498,000	0.16	0.16
Third Quarter	3,613,000	3,411,000	2,447,000	0.26	0.26
Fourth Quarter	3,145,000	1,027,000	722,000	0.08	0.07
	$ 14,265,000	$ 8,075,000	$ 5,760,000	$ 0.62	$ 0.61
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)

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of CREDO Petroleum Corporation

We have audited the accompanying consolidated balance sheet of CREDO Petroleum Corporation and subsidiaries as of October 31, 2009 and 2008, and the related consolidated statements of operations, shareholders equity, and cash flows for the years then ended. 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 audit.

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, 2009 and 2008, and the consolidated results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

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, 2009, 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 7, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young, LLP

Denver, Colorado

January 7, 2010

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, 2009, 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.

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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, 2009, 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, 2009, and the related consolidated statements of operations, shareholders equity, and cash flows for the year then ended and our report dated January 7, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young, LLP

Denver, Colorado

January 7, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders

Credo Petroleum Corporation

We have audited the accompanying consolidated statements of operations, stockholders equity, and cash flows of Credo Petroleum Corporation and subsidiaries for the year ended October 31, 2007. 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 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the results of operations of Credo Petroleum Corporation and

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subsidiaries and their cash flows for the year ended October 31, 2007, in conformity with U.S. generally accepted accounting principles.

***HEIN** & ASSOCIATES LLP*

Denver, Colorado

January 14, 2008, except for matters described in Note 12 as to which the date is September 15, 2008

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, 2009. 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, 2009, 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, 2009, 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.

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The effectiveness of our internal control over financial reporting as of October 31, 2009 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, 2009 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.

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).

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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.
23.2 *	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).

* Filed with this Form 10-K.

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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 7, 2010.

CREDO PETROLEUM CORPORATION
(Registrant)

By: /s/ James T. Huffman
James T. Huffman,
Chairman of the Board of Directors, and
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 7, 2010	/s/ James T. Huffman James T. Huffman	Chairman of the Board of Directors, Treasurer and Chief Executive Officer (Principal Executive Officer)
January 7, 2010	/s/ Alford B. Neely Alford B. Neely	Chief Financial Officer (Principal Financial and Accounting Officer)
January 7, 2010	/s/ Clarence H. Brown Clarence H. Brown	Director
January 7, 2010	/s/ Oakley Hall Oakley Hall	Director
January 7, 2010	/s/ W. Mark Meyer W. Mark Meyer	Director
January 7, 2010	/s/ John A. Rigas John A. Rigas	Director
January 7, 2010	/s/ H. Leigh Severance H. Leigh Severance	Director
January 7, 2010	/s/ William F. Skewes William F. Skewes	Director
January 7, 2010	/s/ Marlis E. Smith, Jr. Marlis E. Smith, Jr.	Director