CREDO PETROLEUM CORP
Form 10-K
January 30, 2006

Table of Contents

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

FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For The Fiscal Year Ended October 31, 2005
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)

Colorado	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 þ 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 þ 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. þ Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. þ

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

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of April 30, 2005, the end of the registrant s most recently completed second quarter was $68,204,000.

As of January 27, 2006, the registrant had 9,163,000 net shares of common stock outstanding.

Table of Contents

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 close 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 March 23, 2006 and is hereby incorporated by reference.

NON-GAAP FINANCIAL MEASURES

In this Annual Report on Form 10-K, the company uses the term cash flow from operating activities (before changes in operating assets and liabilities) 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.

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 relate to, among other things:

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

employee relations;

investment strategy and risk; and

expansion and growth of the company s business and operations.

Table of Contents

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 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.

TABLE OF CONTENTS

PART I

ITEM 1. BUSINESS

General

CREDO Petroleum Corporation (CREDO) was incorporated in Colorado in 1978. 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 region of the United States. The company has operating activities in nine states and has twelve 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.

The company effected a three-for-two stock split in each of fiscal 2005 and 2004. All share and per share amounts discussed and disclosed in this Annual Report on Form 10-K reflect the effect of these stock splits. In addition, the company effected a 20% stock dividend in fiscal 2003.

Business Activities

During 2005, the company made important strategic decisions and commitments to new projects designed to sustain the company s growth rate by expanding and diversifying its business, both technically and geographically. These new projects will also diversify the capital exposure, risk and reserve potential of the company s drilling activities. This includes approximately equal commitments to conventional drilling and to the company s patented Calliope Gas Recovery System (Calliope) operations.

The company s goal is to create steady growth by adding production and long-lived reserves at reasonable costs and risks. The strategy employed by the company to achieve this goal involves conventional drilling and increasing the number of Calliope installations.

Historically, the company s primary drilling focus has been on the shelf of the Northern Anadarko Basin of Oklahoma. The company will continue generating prospects and drilling on this acreage concentrating on medium depth properties generally ranging from 7,000 to 10,000 feet. Third party industry participants are involved in most of the company s operating activities.

During 2005, the company significantly expanded both the volume and breadth of its exploration program with new projects in South Texas and north-central Kansas. Compared to drilling in Oklahoma, the South Texas project involves higher costs and greater risks but significantly higher per well reserve potential. The South Texas project is 3-D seismic driven with well depths ranging from 10,000 to 15,500 feet. The north-central Kansas project is geared to oil exploration and has excellent potential to add significant reserves at moderate costs and risks. This project is also 3-D seismic driven with well depths approximating 4,000 feet. Exploration teams for both projects specialize in their respective geographic areas and have been highly successful finding new reserves using 3-D seismic. The company believes that both projects have the potential to generate significant future production and reserve growth.

Over the past five years, the company has participated in developing, testing, refining, and patenting Calliope. 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 clearly different 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 a 10 year unrestricted exclusive license for the Calliope technology which can be extended, at the company s option, to cover the term of the latest patent. External sources of capital have not been required for the development, refinement or installation of Calliope. At October 31, 2005, Calliope has been installed on 22 wells ranging in depth from 6,500 feet to 18,400 feet. The company has proven Calliope s economic viability and flexibility over a wide range of applications.

The company significantly expanded its Calliope operations in 2005 by moving into Texas and Louisiana and has entered into discussions with other companies regarding the formation of joint venture arrangements that utilize Calliope. In addition, higher gas prices have facilitated a new Calliope project to drill wells into low-pressure reservoirs containing substantial stranded gas reserves. Calliope will then be used to recover those reserves. This is expected to enhance the company s control over monetizing Calliope s value while providing the opportunity to optimize Calliope s performance and broaden the range of reservoirs for Calliope applications.

The company acts as operator of approximately 108 wells pursuant to standard industry operating agreements. The company owns interests in approximately 1,400 wells of which approximately 1,150 wells, represent small overriding royalty interests.

Markets and Customers

Marketing of the company s oil and gas production is influenced by many factors which are beyond the company s control, 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 2003, the posted price for West Texas intermediate fell below $25.00 per barrel and then rose to over $60.00 per barrel late in 2005.

Natural gas price decontrol, the advent of an active spot market for natural gas, changes in supply and demand for natural gas, and weather patterns cause natural gas prices to be subject to significant fluctuations. The company presently sells virtually all of its natural gas under one 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.

Over the past few years there has been increasing concern that a supply/demand imbalance has developed in domestic natural gas based on increasing demand and lower deliverability. This, together with rising oil prices, political unrest and uncertainty in certain major producing regions, supply vulnerability to natural disasters, such as hurricanes, and active speculation in the natural gas futures market has caused natural gas prices to become increasingly volatile. The company expects strong natural gas prices to continue for several years 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 and collars on the NYMEX futures market.

Oil production is sold to crude oil purchasing companies at competitive spot 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 in major producing regions. Political unrest and market uncertainty in the Middle East, Africa, South America and former Soviet Union, OPEC s renewed cooperation in managing the price of its produced oil, and increased demand from countries with developing economies, such as China and India, have resulted in higher world-wide oil prices during the past several years.

Table of Contents

Information concerning the company s major customers is included in Note (8) to the Consolidated Financial Statements.

Competition and Regulation

The oil and gas industry is highly competitive. As a small independent, the company must compete against companies with substantially larger 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. To date, such regulations have not had a material effect on the company s operations, or the costs thereof. 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 does not believe that capital expenditures related to environmental control facilities or other regulatory matters will be material in 2006. 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.

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.

Table of Contents

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 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. If oil and natural gas prices decrease, 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 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, 2005, approximately 11% 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.

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.

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 54 properties which represent 28% of the company s total properties but a disproportionate 76% of the discounted value (at 10%) of the company s reserves. Individual wells on which Calliope is installed comprise 22% of these significant properties and 32% of the discounted reserve value of such properties. Relatively new wells comprise 22% of these significant properties and 24% of the discounted reserve value of such properties.

Estimates of reserve quantities and values for these properties must be viewed as being subject to significant change as more data about the properties becomes available. Such properties include wells with limited production histories and properties with proved undeveloped or proved non-producing reserves. In addition, Calliope is generally installed on mature wells. As such, they contain older down-hole equipment that is more subject to failure than new equipment. The failure of such equipment, particularly casing, can result in complete loss of a well.

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

Major oil companies, independent producers, and institutional and individual investors are actively seeking oil and gas properties throughout the world, along with the equipment, labor and materials required to develop and operate properties. Shortages for 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.

The company s hedging arrangements 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 hedging 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 hedge. 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 expected;
- the contractual counterparties fail to perform under the contracts; or

Table of Contents

- a sudden, unexpected event, materially impacts natural gas prices.

The terms of the company s hedging 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.

In addition, hedging transactions using derivative instruments involve basis risk. Basis risk in a hedging contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective.

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. We maintain insurance against some, but not all, of these risks. Management believes that the level of insurance against these risks is reasonable and is in accordance with industry practices. The occurrence of a significant event, however, that is not fully insured could have a material adverse effect on our financial position and results of operations.

The company s operations are subject to a variety of contractual, regulatory and other constraints.

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

- 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.

Because current regulations covering the company s operations are subject to change at any time, and despite its belief that it is in substantial compliance with applicable environmental and other government laws and regulations, the company may 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.

Table of Contents

The company is highly dependent on the services of one of its officers.

The company is highly dependent on the services of James T. Huffman, our President and Chief Executive Officer. The loss of Mr. Huffman could have a material adverse effect on the company.

ITEM 2. PROPERTIES

General

The company s drilling activities are primarily located along the shelf of the Northern Anadarko Basin of Oklahoma and in the Oklahoma Panhandle where the company owns interests in 73,000 gross acres. Specifically, drilling expenditures have been focused on prospects located in Harper, Ellis and Beaver Counties, Oklahoma. Wells target the Morrow and Chester formations between 7,000 and 10,000 feet. Since 2001, the company has participated in drilling 59 wells on the prospects with interests ranging up to 69%. Of those wells, 46 were completed as producers and 13 were dry holes. Several of the wells are exceptional for the area, and 11 of the wells are included in the company s Significant Properties (see definition below). Several of the prospects have ample room for additional drilling and the company believes that more good wells will be drilled.

The company owns the exclusive right to the Calliope Gas Recovery System. The company believes it has proven that Calliope will add 0.5 to 2.0 Bcf of proved gas reserves to many dead and uneconomic wells. The company also 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.

Calliope operations are currently focused in Oklahoma where the company has a significant field operations infrastructure. Most Calliope wells are located in the Northern Anadarko Basin of Oklahoma. To date, Calliope has been installed on 22 wells ranging in depth from 6,500 to 18,400 feet. All of the wells were either dead or uneconomic at the time Calliope was installed. Twelve Calliope wells are included in the company s Significant Properties. Recently, the company has expanded its Calliope operations into Texas and Louisiana.

For additional information regarding current year activities, including oil and gas production, refer to Management s Discussion and Analysis of Financial Condition and Results of Operations .

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

The company s reserves, and reserve values, are concentrated in 54 properties (Significant Properties). Some of the Significant Properties are individual wells and others are multi-well properties. At year-end, Significant Properties represent 28% of the company s total properties but a disproportionate 76% of the discounted value (at 10%) of the company s reserves. Individual Calliope wells comprise 22% of the Significant Properties and represent 32% of the discounted reserve value of such properties. Wells drilled on the prospects discussed above (Item 2. Properties, General) comprise 22% of the Significant Properties and represent 24% of the discounted reserve 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 (including post Calliope installation wells) 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.

Table of Contents

McCartney Engineering, Inc., an independent petroleum engineering firm, estimated proved reserves for the company s properties which represented 63% in 2005, 61% in 2004, and 64% in 2003 of the total estimated future value of estimated reserves. Remaining reserves were estimated by the company in all years. At October 31, 2005, natural gas represented 87% and crude oil represented 13% 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 (8) to the Consolidated Financial Statements where additional reserve information is provided. The average price used to calculate estimated future net revenues was $55.59, $50.43 and $28.64 per barrel of oil and $10.26, $5.84, and $3.99 per Mcf of gas as of October 31, 2005, 2004, and 2003, respectively. Amounts do not include estimates of future Federal and state income taxes.

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

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

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 are net of any hedging gains or losses.

	2005		2004		2003	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**1,830,000**	**$ 6.16**	1,710,000	$ 4.60	1,449,000	$ 4.50
Oil (bbls)	**37,000**	**$50.90**	41,000	$36.57	35,000	$27.68

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 $1.35, $1.06, and $0.97 per Mcfe in 2005, 2004, and 2003, respectively.

Productive Wells and Developed Acreage

Developed acreage at October 31, 2005 totaled 26,000 net and 118,000 gross acres. At October 31, 2005, the company owned working interests in 75.45 net (257 gross) wells consisting of 16.23 net (43 gross) oil wells and 59.22 net (214 gross) natural gas wells. In addition, the company owned royalty and production payment interests in approximately 1,150 wells, primarily coal bed methane located in Wyoming. In 2005, the company sold or abandoned 1.30 net (4 gross) wells. In the same period, the company drilled and acquired interests in 7.22 net (31 gross) wells in which it did not previously own an interest.

Undeveloped Acreage

The following table sets forth the number of undeveloped acres (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 Gross	Royalty Interest Acreage Net	Working Interest Acreage Gross	Working Interest Acreage Net
2006	3,100		17,800	7,200
2007	2,700		20,300	8,200
2008			10,100	3,600
2009			700	200
2010	3,300	100	5,000	1,000
Thereafter	1,000	500	4,000	1,600
Held-By-Production	151,200	8,000	11,800	2,300
Total	161,300	8,600	69,700	24,100

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 Oil	Exploratory Gas	Exploratory Dry	Development Oil	Development Gas	Development Dry
2005	**29**		**10**	**2**		**14**	
2004	25	1	3	4		14	3
2003	21		12	3		6	
1978-2002	234	12	101	78	15	23	5
Total	309	13	126	87	15	57	8

Net Wells

Year Ended October 31,	Total Net Wells	Exploratory Oil	Exploratory Gas	Exploratory Dry	Development Oil	Development Gas	Development Dry
2005	**4.683**		**3.075**	**0.208**		**1.400**	
2004	6.899	.306	1.381	2.074		1.980	1.158
2003	4.906		2.564	0.762		1.580	
1978-2002	38.927	1.557	16.062	12.418	4.350	2.555	1.985
Total	55.415	1.863	23.082	15.462	4.350	7.515	3.143

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 and excess liability.

Facilities and Employees

The company s corporate headquarters are located at 1801 Broadway, Suite 900, Denver, Colorado, in approximately 4,000 square feet occupied under a lease. The company believes

13

Table of Contents

that this space is adequate for its current needs. The company s current lease expires in April 2006. The company has finalized negotiations with its landlord and expects to renew its office lease in the second quarter of 2006.

As of October 31, 2005, the company had 12 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, (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 is not a party to any material pending legal proceedings. No such proceedings have been threatened and none are contemplated by the company.

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 2005.

PART II

ITEM 5. MARKET FOR THE REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

The company s common stock is traded on the National Association of Securities Dealers Automated Quotation System under the symbol CRED . Market quotations shown below were reported by the National Association of Securities Dealers, Inc. and represent prices between dealers excluding retail mark-up or commissions and may not necessarily represent actual transactions.

	2005		2004	
Quarter Ended	**High**	**Low**	High	Low
January 31	**$ 9.93**	**$ 8.21**	$ 9.00	$7.14
April 30	**$11.29**	**$ 9.00**	$11.11	$7.99
July 31	**$11.99**	**$ 9.15**	$12.53	$9.34
October 31	**$18.80**	**$11.87**	$11.59	$8.18

At January 20, 2006, the company had 2,752 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.

The company did not repurchase any shares of its common stock during the fiscal quarter ended October 31, 2005.

Table of Contents

Equity Compensation Plan Information:

The following table summarizes the company s equity compensation plan under which securities may be issued as of October 31, 2005. The only types of equity compensation plans that the company has are plans that authorize the granting of options to purchase shares of its common stock.

Plan Category	Number of securities to be issued upon exercise of outstanding options (a)	Weighted-average per share exercise price of outstanding options (b)	Number of securities remaining available for future issuance under the equity compensation plan (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	485,064	$ 5.78	109,995
Equity compensation plans not approved by security holders			
Total	485,064	$ 5.78	109,995

A description of the company s equity compensation plan is contained in Note 2 to the Consolidated Financial Statements contained elsewhere in this document.

Table of Contents

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, 2005 were derived from the audited financial statements and the accompanying notes to those financial statements.

	Years Ended October 31,				
	2005	2004	2003	2002	2001
Audited Financial Information					
Statement of Operations Data:					
Oil and gas sales	$ 13,143,000	$ 9,367,000	$ 7,494,000	$ 4,698,000	$ 5,163,000
Operating revenue	668,000	604,000	536,000	488,000	456,000
Investment and other income	146,000	343,000	461,000	172,000	188,000
Oil and gas production expense	2,759,000	2,075,000	1,608,000	1,291,000	1,135,000
Depreciation, depletion and amortization	2,402,000	1,747,000	1,333,000	1,202,000	842,000
General and administrative	1,497,000	1,383,000	1,257,000	1,060,000	957,000
Interest expense	37,000	39,000	46,000	49,000	53,000
Income before income taxes and cumulative effect of change in accounting principle	7,262,000	5,070,000	4,247,000	1,756,000	2,820,000
Net income	5,229,000	3,650,000	3,130,000	1,282,000	2,002,000
Net income per share[(1)]:					
Basic	$ 0.58	$ 0.40	$ 0.35	$ 0.15	$ 0.24
Diluted	$ 0.56	$ 0.39	$ 0.35	$ 0.14	$ 0.23
Weighted-average shares outstanding[(1)]:					
Basic	9,080,000	9,036,000	8,869,000	8,761,000	8,397,000
Diluted	9,367,000	9,282,000	9,042,000	8,952,000	8,832,000
Balance Sheet Data:					
Working capital	7,697,000	5,611,000	6,577,000	6,630,000	5,791,000
Total assets	37,844,000	30,976,000	23,572,000	18,811,000	16,470,000
Long-term obligations:					
Exclusive license agreement obligation	233,000	297,000	355,000	408,000	456,000
Stockholders equity	26,947,000	20,920,000	17,635,000	14,307,000	12,843,000
Cash dividends declared per common share					
Unaudited Operating Data					
Production Volumes:					

Gas (Mcf)	1,830,000	1,710,000	1,449,000	1,298,000	800,000
Oil (Bbls)	37,000	41,000	35,000	37,000	44,000
MCFE	2,050,000	1,960,000	1,660,000	1,520,000	1,140,000
Average sales price before hedging:					
Per Mcf	$ 6.55	$ 5.02	$ 4.57	$ 2.61	$ 4.17
Per Bbls	$ 50.90	$ 36.57	$ 27.68	$ 22.01	$ 26.45
Average sales price after hedging:					
Per Mcf	$ 6.16	$ 4.60	$ 4.50	$ 3.00	$ 5.00
Per Bbls	$ 50.90	$ 36.57	$ 27.68	$ 22.01	$ 26.45
Reserves:					
Gas (Mcf)	15,516,000	15,273,000	13,786,000	9,415,000	9,121,000
Oil (Bbls)	386,000	407,000	385,000	337,000	330,000
Mcfe	17,835,000	17,717,000	16,097,000	11,435,000	11,099,000
Estimated future net revenues	$136,878,000	$77,612,000	$45,165,000	$29,774,000	$21,843,000
Estimated future net revenues discounted at 10%	$ 81,209,000	$44,551,000	$28,024,000	$18,035,000	$13,874,000

(1) The effect of the three for two stock splits in 2005 and 2004 are reflected in all historical share and per share data.

Table of Contents

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

Liquidity and Capital Resources

At October 31, 2005, working capital was $7,697,000, compared to $5,611,000 at October 31, 2004. For the year ended October 31, 2005, net cash provided by operating activities increased 91% to $8,821,000 compared to net cash provided by operating activities of $4,618,000 for the same period in 2004. This increase is primarily the result of increases in net income and other non-cash items (DD&A, deferred income taxes, cumulative effect of change in accounting principal and other) of $2,080,000; a net decrease of $876,000 in short term investments in 2005 versus a net increase in short term investments of $1,593,000 in 2004 which resulted in a net increase of $2,469,000 between the two periods; a net increase in cash as a result of changes in accrued oil and gas sales, trade receivables and other current assets of $899,000; and a net decrease in cash as a result of changes in accounts payable and income taxes payable of $1,245,000. For the year ended October 31, 2005 and 2004, net cash used in investing activities was $7,667,000 and $6,179,000, respectively. Investing activities primarily included oil and gas exploration and development expenditures, including Calliope, totaling $6,938,000 and $5,671,000, respectively.

The average return on the company s investments for the year ended October 31, 2005 and 2004 was 2.8% and 5.0%, respectively. At October 31, 2005, approximately 52% of the investments were directly invested in mutual funds and were managed by professional money managers. Remaining investments are in managed partnerships that use various strategies to minimize their correlation to stock market movements. Most of the investments are highly liquid and the company believes they represent a responsible approach to cash management. In the company s opinion, the greatest investment risk is the potential for negative market impact from unexpected, major adverse news.

Existing working capital and anticipated cash flow are expected to be sufficient to fund operations and capital requirements for at least the next 12 months. At October 31, 2005 the company had remaining estimated capital requirements of $1,206,000 related to projects in South Texas and along the Central Kansas uplift. Such costs, which include overhead, lease bonuses, land services and 3-D seismic, are expected to be funded over the next 12 to 15 months.

As of October 31, 2005, 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
Exclusive license obligation	$ 375,000	$ 93,750	$ 281,250	$	$
Operating lease obligations	21,500	21,500			
Total	$ 396,500	$ 115,250	$ 281,250	$	$

At October 31, 2005, the company had no lines of credit or other bank financing arrangements except for the hedging line of credit discussed in Note 1 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.

The company s cash flow from operating activities (before changes in operating assets and liabilities) increased approximately $2.1 million for the year ended October 31, 2005. Although cash flow from operating activities (before changes in operating assets and liabilities) is not a generally accepted accounting principles measure of performance or liquidity, the company believes that it may be useful to an investor in evaluating its performance. However, investors should not consider this measure in isolation or as a substitute for operating income, cash flows from operating activities or any other measure for determining the company s operating performance or liquidity that is calculated in accordance with generally accepted accounting principles. In addition, because cash flow from operating activities (before changes in operating assets and liabilities) is not calculated in accordance with generally accepted accounting principles, it may not necessarily be comparable to similarly titled measures employed by other companies. A reconciliation of cash flow from operating activities (before changes in operating assets and liabilities) can be made by adding net income, depreciation, depletion and amortization expense, deferred income taxes, the cumulative effect of change in accounting principal and other as in the table below.

	For The Year Ended October 31,		
	2005	2004	2003
Reconciliation of Cash Flow From Operating Activities (before changes in operating assets and liabilities):			
Net income	$ 5,229,000	$ 3,650,000	$ 3,130,000
Depreciation, depletion and amortization	2,402,000	1,747,000	1,333,000
Deferred income taxes	1,373,000	1,496,000	1,016,000
Cumulative effect of change in accounting principal			(72,000)
Other		34,000	6,000
Cash Flow From Operating Activities (before changes in operating assets and liabilities)	$ 9,004,000	$ 6,927,000	$ 5,413,000

Off-Balance Sheet Financing

The company has no off-balance sheet financing arrangements at October 31, 2005.

Product Prices and Production

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

Although product prices are key to the company s ability to operate profitably and to budget capital expenditures, they are beyond the company s control and are difficult to predict. Since 1991, the company has periodically hedged the price of a portion of its estimated natural gas production when the potential for significant downward price movement is anticipated. Hedging transactions typically take the form of forward short positions and collars on the NYMEX futures market, and are closed by purchasing offsetting positions. Such hedges, which are accounted for as cash flow hedges, do not exceed estimated production volumes, are expected to have reasonable correlation between price movements in the futures market and the cash markets where the company s production is located, and are authorized by the company s Board of Directors. Hedges are expected to be closed as related production occurs but may be closed earlier if the anticipated downward price movement occurs or if the company believes that the potential for such movement has abated.

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

Hedging gains and losses are recognized as adjustments to gas sales as the hedged product is produced. The company had after tax hedging losses of $518,000 in fiscal 2005 and after tax hedging losses of $516,000 in fiscal 2004. Any hedge ineffectiveness, which was not material for the three years ended October 31, 2005, is immediately recognized in gas sales. Subsequent to October 31, 2005, the company closed its December 2005 and January 2006 hedge contracts at expiration (120 MMbtu) with an after tax hedging loss of $227,000. The company currently has no open hedge positions.

Table of Contents

The company has a hedging line of credit with its bank which is available, at the discretion of the company, to meet margin calls. To date, the company has not used this facility and maintains it only as a precaution related to possible margin calls. The maximum credit line is $2,000,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the company to maintain $3,000,000 in cash or short term investments and prohibits unfunded debt in excess of $500,000. It expires on October 31, 2006.
Oil and natural gas sales volume and price realization comparisons for the indicated years ended October 31 are set forth below. Price realizations include hedging gains and losses.

	2005		2004		2003	
Product	**Volume**	**Price**	Volume	Price	Volume	Price
Gas (Mcf)	**1,830,000**	**$ 6.16**	1,710,000	$ 4.60	1,449,000	$ 4.50
% change	**+7%**	**+34%**	+18%	+2%	+12%	+50%
Oil (bbls)	**37,000**	**$50.90**	41,000	$36.57	35,000	$27.68
% change	**-10%**	**+39%**	+18%	+32%	-5%	+26%

Increases in natural gas volumes resulted primarily from successful drilling in Oklahoma. Most oil and condensate volumes are associated with natural gas production and, therefore, vary from well to well depending on the volume and richness of the natural gas produced. Significant Properties (see definition on page 11) contributed 41% of 2005 production on a gas-equivalent basis.
As to Significant Properties, wells drilled since 2001 contributed 40% of 2005 production while Calliope wells installed during the same period contributed 17% of such production. Refer to Item 2, Properties , for disclosures regarding reserve values on Significant Properties.

Oil and Gas Activities

General. Capital spending in 2005 totaled $7,327,000, a 3% increase over last year. During the year the company continued to focus on its two core projects natural gas drilling along the shelf of the Northern Anadarko Basin of Oklahoma and application of its patented Calliope Gas Recovery System.
The company has recently expanded into South Texas through an exploration program using 3-D seismic to define the Vicksburg, Frio, Queen and Wilcox prospects in Hidalgo and Jim Hogg counties and into north-central Kansas through an exploration program using 3-D seismic to define Lansing-Kansas City oil prospects in Graham and Sheridan counties. The company believes that, in combination, its drilling and Calliope projects provide an excellent (and possibly unique) balance for achieving its goal of adding long-lived natural gas reserves and production at reasonable costs and risks.
The company will continue to actively pursue adding reserves through its two core projects in fiscal 2006 and expects these activities to be a reliable source of reserve additions. However, the timing and extent of such activities can be dependent on many factors which are beyond the company s control, including but not limited to, the availability of oil field services such as drilling rigs, production equipment and related services and access to wells for application of the company s patented liquid lift system on low pressure gas wells. The prevailing price of oil and natural gas has a significant affect on demand and, thus, the related cost of such services and wells.
Drilling Activities. The company currently drills primarily on its 73,000 gross acre inventory located along the northern shelf of the Anadarko Basin. During 2005, the company drilled 12 wells in Oklahoma with working interests ranging up to 69%. Ten of these wells have been completed as producers. The wells, which ranged from development to rank wildcat, are located on five different prospects. Drilling expenditures were concentrated on the company s acreage inventory located along the northern shelf of the Anadarko Basin of

Oklahoma. The wells targeted the Morrow, Oswego and Chester formations between 7,000 and 10,000 feet. A substantial number of additional wells are anticipated for the area.

Drilling is not restricted to the northern Anadarko shelf acreage. The company is generating prospects elsewhere in the Northern Anadarko Basin, in the Oklahoma Panhandle, north-central Oklahoma, north-central Kansas and South Texas. In addition, 14 coal bed methane wells were drilled on acreage in Wyoming where the company owns working interests of approximately 10%, and 160 coal bed methane wells were drilled on Wyoming acreage where the company owns small royalty interests.

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

As previously discussed, drilling of generated South Texas prospects is not covered by the exploration agreement and, therefore, is not a capital requirement under the exploration agreement. Drilling is expected to commence in early 2006. The initial four well drilling program will be located in Hidalgo and Jim Hogg Counties and wells will range in depth from 10,200 to 15,500 feet with an estimated total cost (8\8ths basis) of approximately $14,000,000. Completed well costs are estimated to range from $1,500,000 at 10,000 feet to $6,500,000 at 15,500 feet. The company is currently evaluating what portion of its 37.5% after payout interest to retain for direct participation.

The north-central Kansas project agreement provides for approximately 28 square miles of 3-D seismic to be collected and evaluated and five exploratory wells to be drilled. Completed well costs are estimated to be approximately $280,000. Drilling will commence after new 3-D seismic shooting and interpretation is completed, which is expected in mid-2006.

The company replaced 106% of its 2005 production. Per unit finding costs were $2.73 per Mcf in gas equivalents excluding start-up costs in South Texas and north-central Kansas.

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.

Calliope Gas Recovery Technology. The company owns the exclusive right to a patented technology known as the Calliope Gas Recovery System. Calliope can achieve substantially lower flowing bottom hole pressure than conventional production methods because it does not rely on reservoir pressure to lift liquids. Lower bottom hole pressure can translate into recovery of substantial additional natural gas reserves.

Calliope has proven to be reliable and flexible over a wide range of applications on wells the company owns and operates. It has also proven to be consistently successful. Accordingly, the company has recently begun implementing strategies designed to widen the envelope of wells on which Calliope should be installed.

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

Higher natural gas prices have facilitated a new project to drill wells into low-pressure natural gas reservoirs. Many low-pressure reservoirs, including abandoned fields, contain substantial stranded natural gas that can be recovered by Calliope. This project is designed to ramp-up the number of Calliope installations, improve the company s control over monetizing Calliope s value, control configuration of wellbores for optimum Calliope performance, and broaden the range of reservoirs for Calliope applications. Completed well costs are estimated to be approximately $2,200,000 including installation of Calliope. The company expects to commence drilling wells for Calliope applications in mid-2006 and is considering bringing in industry participants for the project.

As previously reported, joint venture presentations have been made to a range of companies, including several of the major oil and gas companies as well as several large independents. All of these companies have expressed a keen interest in Calliope, and joint venture discussions are continuing with several of those companies, including evaluation of candidate wells.

In addition to joint ventures and the Calliope drilling project, the company has successfully expanded its Calliope operations into Texas and Louisiana. In southwest Texas, the company recently completed two prototype Calliope installations which once again broadened Calliope s down-hole application, successfully lifting several times more fluid volume than Calliope has previously lifted from the company s Oklahoma wells. Although this prototype Calliope configuration limits the amount of natural gas that can be produced during the start-up and dewatering phase, after initial dewatering and once liquid production stabilizes, the system can be optimized to allow greater natural gas flow. In Louisiana, the company recently completed the purchase of a Calliope candidate well in Acadia Parish. The well is currently dead and will be evaluated for a Calliope installation in the first quarter of 2006. These efforts are being spearheaded on a full-time basis by a highly qualified petroleum engineer based in Houston.

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

Results of Operations

In 2005, total revenues increased 35% to $13,957,000 compared to $10,314,000 last year. As the oil and gas price/volume table on page 19 shows, total gas price realizations, which reflect hedging transactions, increased 34% to $6.16 per Mcf and oil price realizations increased 39% to $50.90 per barrel. The net effect of these price changes was to increase oil and gas sales by $3,253,000. Hedging losses were $719,000 in 2005 compared to $717,000 in 2004. During the same period, the company s gas equivalent production increased 5% resulting in an increase to oil and gas sales of $523,000. Operating income increased 11% due to an increase in drilling and production supervision income related to operated wells. Investment and other income decreased 57% primarily due to a decrease in other income.

In 2005, total costs and expenses rose 28% to $6,695,000 compared to $5,244,000 for last year. Oil and gas production expenses increased 33% due primarily to new wells. Depreciation, depletion and amortization (DD&A) increased 37% primarily due to increased production volumes and an increase in the amortizable full cost pool. General and administrative expenses increased 8% primarily due to increases in professional fees and salaries and benefit costs related primarily to increased administration resulting from rapid growth, transition from small business SEC reporting status to full reporting status, compliance with Sarbanes-Oxley regulations and preparation for accelerated filing requirements related to the company s quarterly and annual SEC reports. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 28% for the 2005 and 2004 periods.

Table of Contents

In 2004, total revenues rose 21% to $10,314,000 compared to $8,491,000 in 2003. As the oil and gas price/volume table on page 19 shows, total gas price realizations, which reflect hedging transactions, rose 2% to $4.60 per Mcf and oil price realizations rose 32% to $36.57 per barrel. The net effect of these price changes was to increase oil and gas sales by $448,000. Hedging losses were $717,000 in 2004 compared to $92,000 in 2003. Gas and oil production both rose 18%. The net effect of these volume changes was to increase oil and gas sales by $1,425,000. The increase in volumes resulted primarily from successful drilling in 2004 and 2003. Operating income rose 13% due to drilling supervision income and additional operated wells. Investment income and other fell 26% due primarily to market declines.

In 2004, total costs and expenses rose 24% to $5,244,000 compared to $4,244,000 in 2003. Oil and gas production expenses rose 29% due primarily to increased production taxes on higher revenues and new wells added during the year. DD&A increased 31% due primarily to increased production volume. General and administrative expenses rose 10% primarily due to increases in salaries and benefit costs. Interest expense relates to the exclusive license agreement note payment. The effective tax rate was 28% in 2004 and 2003.

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.

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

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

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

The company has made only one ceiling write-down in its 27-year history. That write down was made in 1986 after oil prices fell 51% and natural gas prices fell 45% between fiscal year end 1985 and 1986.

Changes in oil and natural gas prices have historically had the most significant impact on the company s ceiling test. In general, the ceiling is lower when prices are lower. Even though oil and natural gas prices can be highly volatile over weeks and even days, the ceiling calculation dictates that prices in effect as of the last day of the test period be

Table of Contents

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.

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

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

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

One measure of the life of the company s proved reserves can be calculated by dividing proved reserves at fiscal year end 2005 by production for fiscal year 2005. This measure yields an average reserve life of nine 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. Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations requires that the company estimate the future cost of asset retirement obligations, discount that cost to its present value, and record a corresponding asset and liability in its Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including future abandonment costs, inflation, market risk premiums, useful life, and cost of capital. The nature of these estimates requires the company to make judgments based on historical experience and future expectations. Revisions to the estimates may be required based on such things as changes to cost estimates or the timing of future cash outlays. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis.

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 153, Exchange of Non-monetary Assets. This statement is based on the principle that exchanges of non-monetary assets should be measured based on the fair value of the assets exchanges. SFAS 153 is effective for non monetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The company does not expect that the adoption of SFAS No. 153 will have an impact on the company s financial statements.

The Securities and Exchange Commission (SEC) recently issued guidance on the ways in which its full-cost rules interact with the accounting requirements that the FASB established for asset retirement obligations specifically, how SFAS No. 143, Accounting for Asset Retirement Obligations, interacts with the full-cost requirements in Rule 4-10 of Regulation S-X (Rule 4-10). The SEC s new guidance appears in Staff Accounting Bulletin (SAB) No. 106 issued in October 2004. The adoption of SAB No. 106 did not have an impact on the company s financial statements.

In March 2005, the FASB issued Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations An Interpretation of SFAS No. 143 , which clarifies the term conditional asset retirement obligation used in SFAS No. 143, Accounting for Asset Retirement Obligations , and specifically when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The adoption did not have an impact on the company s financial statements.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections , which replaces Accounting principles Board Opinion No. 20, Accounting Changes and SFAS No. 3. SFAS 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The company does not expect that the adoption of SFAS No. 154 will have an impact on the company s financial statements.

In December 2004, the FASB issued SFAS No. 123 (Revised 2004), Share-Based Payment , that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for (a) equity instruments of the company or (b) liabilities that are based on the fair value of the company s equity instruments or that may be settled by the issuance of such equity instruments. SFAS No. 123R addresses all forms of share-based payment awards, including shares issued under employee stock purchase plans, stock options, restricted stock and stock appreciation rights. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25, Accounting for Stock Issued to Employees , that was provided in Statement 123 as originally issued. Under SFAS No. 123R companies are required to record compensation expense for all share based payment award transactions measured at fair value. This statement is effective for fiscal years beginning after June 15, 2005. The company will implement SFAS 123R in the first quarter of the company s fiscal year beginning November 1, 2005. The company is currently evaluating the impact of this new standard, and estimates that the impact of applying the various provisions of SFAS No. 123R will result in an expense similar to the pro-forma effects reported elsewhere in this Annual Report on Form 10-K if all current unvested stock options vest on the scheduled dates and the assumptions in the Black-Scholes model remain the same.

Table of Contents

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 collars and forward short positions in the NYMEX futures market. 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. The company currently has no open hedge positions.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

Table of Contents

CONSOLIDATED BALANCE SHEETS
October 31, 2005 and 2004

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

ASSETS	2005	2004
Current assets:		
Cash and cash equivalents	**$ 1,935,000**	$ 518,000
Short-term investments	**5,495,000**	6,371,000
Receivables:		
Trade	**1,003,000**	1,019,000
Accrued oil and gas sales	**2,776,000**	2,051,000
Other current assets	**245,000**	58,000
Total current assets	**11,454,000**	10,017,000
Long-term assets:		
Oil and gas properties, at cost, using full cost method:		
Unevaluated oil and gas properties	**3,452,000**	2,174,000
Evaluated oil and gas properties	**36,121,000**	30,072,000
Less: accumulated depreciation, depletion and amortization of oil and gas properties	**(15,022,000)**	(12,737,000)
Net oil and gas properties, at cost, using full cost method	**24,551,000**	19,509,000
Exclusive license agreement, net of accumulated amortization of $361,000 in 2005 and $291,000 in 2004	**338,000**	408,000
Inventory	**1,288,000**	883,000
Other, net	**213,000**	159,000
Total assets	**$ 37,844,000**	$ 30,976,000

LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 3,426,000**	$ 4,394,000
Income taxes payable	**331,000**	12,000
Total current liabilities	**3,757,000**	4,406,000
Long-term liabilities:		
Deferred income taxes, net	**5,978,000**	4,605,000
	233,000	297,000

Exclusive license obligation, less current obligations of $64,000 in 2005 and $58,000 in 2004		
Asset retirement obligation	**929,000**	748,000
Total liabilities	**10,897,000**	10,056,000
Commitments:		
Stockholders equity:		
Preferred stock, no par value, 5,000,000 shares authorized, none issued		
Common stock, $.10 par value, 20,000,000 shares authorized, 9,510,000 shares issued and outstanding in 2005 and 2004	**951,000**	951,000
Capital in excess of par value	**12,486,000**	12,146,000
Treasury stock, at cost, 393,000 shares in 2005, and 454,000 shares in 2004	**(125,000)**	(452,000)
Accumulated other comprehensive loss	**(306,000)**	(437,000)
Retained earnings net of $6,277,000 related to 20% stock dividend in 2003	**13,941,000**	8,712,000
Total stockholders equity	**26,947,000**	20,920,000
Total liabilities and stockholders equity	**$ 37,844,000**	$ 30,976,000

See accompanying notes to consolidated financial statements.

Table of Contents

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Three Years Ended October 31, 2005

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2005	2004	2003
Revenues:			
Oil and gas sales	**$ 13,143,000**	$ 9,367,000	$ 7,494,000
Operating	**668,000**	604,000	536,000
Investment and other income	**146,000**	343,000	461,000
	13,957,000	10,314,000	8,491,000
Costs and expenses:			
Oil and gas production	**2,759,000**	2,075,000	1,608,000
Depreciation, depletion and amortization	**2,402,000**	1,747,000	1,333,000
General and administrative	**1,497,000**	1,383,000	1,257,000
Interest	**37,000**	39,000	46,000
	6,695,000	5,244,000	4,244,000
Income before income taxes and cumulative effect of accounting change	**7,262,000**	5,070,000	4,247,000
Income taxes	**(2,033,000)**	(1,420,000)	(1,189,000)
Income before cumulative effect of accounting change	**5,229,000**	3,650,000	3,058,000
Cumulative effect of change in accounting principle			72,000
Net income	**$ 5,229,000**	$ 3,650,000	$ 3,130,000
Basic income per share before accounting change	**$ .58**	$ .40	$ .34
Cumulative effect of change in accounting principle, net of tax			.01
Basic income per share	**$ .58**	$ .40	$ .35
Diluted income per share before accounting change	$ **.56**	$ .39	$ .34
Cumulative effect of change in accounting principle, net of tax			.01

Diluted income per share	**$**	**.56**	$	.39	$	.35
Weighted average number of shares of common stock and dilutive securities:						
Basic		**9,080,000**		9,036,000		8,869,000
Diluted		**9,367,000**		9,282,000		9,042,000

See accompanying notes to consolidated financial statements.

Table of Contents

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
For the Three Years Ended October 31, 2005

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	Common Stock		Capital In Excess Of Par Value	Treasury Stock	Accumulated Other Comprehensive Income(Loss)	Comprehensive Income	Retained Earnings	Total Stockholders' Equity
	Shares	Amount						
Balances, October 31, 2002	8,034,000	$ 803,000	$ 6,017,000	$ (759,000)	$ 37,000		$ 8,209,000	$ 14,307,000
Comprehensive income:								
Net income						$ 3,130,000	3,130,000	3,130,000
Other comprehensive income, net of tax:								
Change in fair value of derivatives					143,000	143,000		143,000
Comprehensive income						$ 3,273,000		
20% stock dividend	1,476,000	148,000	6,129,000				(6,277,000)	
Purchase of treasury stock				(1,000)				(1,000)
Exercise of stock options				56,000				56,000
Balances, October 31, 2003	9,510,000	951,000	12,146,000	(704,000)	180,000		5,062,000	17,635,000
Comprehensive income:								
Net income						$ 3,650,000	3,650,000	3,650,000
Other comprehensive income (loss), net of tax:								

Change in fair value of derivatives					(617,000)	(617,000)		(617,000)
Comprehensive income						$ 3,033,000		
Purchase of treasury stock				(39,000)				(39,000)
Exercise of stock options				291,000				291,000
Balances, October 31, 2004	9,510,000	951,000	12,146,000	(452,000)	(437,000)		8,712,000	20,920,000
Comprehensive income:								
Net income						$ 5,229,000	5,229,000	5,229,000
Other comprehensive income:								
Change in fair value of derivatives, net of tax					131,000	131,000		131,000
Total comprehensive income						$ 5,360,000		
Purchase of treasury stock				(8,000)				(8,000)
Exercise of common stock options				335,000				335,000
Tax benefit from the exercise of common stock options			340,000					340,000
Balance, October 31, 2005	9,510,000	$ 951,000	$ 12,486,000	$ (125,000)	$ (306,000)		$ 13,941,000	$ 26,947,000

See accompanying notes to consolidated financial statements.

Table of Contents

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Three Years Ended October 31, 2005

CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

	2005	2004	2003
Cash flows from operating activities:			
Net income	**$ 5,229,000**	$ 3,650,000	$ 3,130,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**2,402,000**	1,747,000	1,333,000
Deferred income taxes	**1,373,000**	1,496,000	1,016,000
Cumulative effect of change in accounting principle			(72,000)
Other		34,000	6,000
Changes in operating assets and liabilities:			
Proceeds from short-term investments	**2,500,000**	944,000	5,261,000
Purchase of short-term investments	**(1,624,000)**	(2,537,000)	(4,453,000)
Trade receivables	**16,000**	(609,000)	167,000
Accrued oil and gas sales	**(725,000)**	(795,000)	(721,000)
Other current assets	**299,000**	95,000	299,000
Accounts payable and accrued liabilities	**(968,000)**	791,000	(236,000)
Income taxes payable	**319,000**	(198,000)	161,000
Net cash provided by operating activities	**8,821,000**	4,618,000	5,891,000
Cash flows from investing activities:			
Additions to oil and gas properties	**(6,938,000)**	(5,671,000)	(5,520,000)
Proceeds from sale of oil and gas properties	**180,000**	317,000	526,000
Changes in other long-term assets	**(909,000)**	(825,000)	(338,000)
Net cash used in investing activities	**(7,667,000)**	(6,179,000)	(5,332,000)
Cash flows from financing activities:			
Proceeds from exercise of stock options	**335,000**	291,000	56,000
Purchase of treasury stock	**(8,000)**	(39,000)	(1,000)
Principal payment on exclusive license obligation	**(64,000)**	(58,000)	(53,000)
Net cash provided by financing activities	**263,000**	194,000	2,000
Increase (decrease) in cash and cash equivalents	**1,417,000**	(1,367,000)	561,000
Cash and cash equivalents:			

Beginning of period	**518,000**	1,885,000	1,324,000
End of period	**$ 1,935,000**	$ 518,000	$ 1,885,000
Supplemental Cash Flow Information:			
Cash paid during the period for income taxes	**$ 100,000**	$ 194,000	$
Cash paid during the period for interest	**$ 36,000**	$ 41,000	$ 46,000

See accompanying notes to consolidated financial statements.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
October 31, 2005
CREDO PETROLEUM CORPORATION AND SUBSIDIARIES
(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
Nature of Operations and Basis of Presentation

The consolidated financial statements include the accounts of CREDO Petroleum Corporation and its wholly owned subsidiaries (the company). The company engages in oil and gas acquisition, exploration, development and production activities in the United States. Certain operations are conducted through limited partnerships and limited liability companies which, as general partner or member company, the company manages and controls. The company s interests in these entities are combined on the proportionate share basis in accordance with accepted industry practice. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to prior year amounts with no effect on previously reported net income. All references to years in these Notes refer to the company s fiscal October 31 year. The company effected a three-for two stock split in each of fiscal 2005 and 2004. All share and per share amounts discussed and disclosed in this Annual Report on Form 10-K reflect the effect of these stock splits.

Cash, Cash Equivalents, and Short-Term Investments

Cash equivalents consist of highly liquid investments with original maturities of three months or less. At October 31, 2005, approximately 52% of short-term investments are mutual funds. Other short-term investments consist primarily of professionally managed limited partnerships which provide readily determinable market values and short-term liquidity. The partnerships are invested primarily in financial instruments. Unrealized gains on limited partnerships are not significant. 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. 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 natural gas and crude oil. The company reports revenue gross for the amounts received before taking into account production taxes and transportation costs which are reported as separate expenses. Revenue is recorded in the month production is delivered to the purchaser at which time title changes hands. Payment is generally received between 30 and 90 days after the date of production. The company makes estimates of the amount of production delivered to purchasers and the prices it will receive. The company uses its knowledge of its properties; their historical performance; the anticipated effect of weather conditions during the month of production; NYMEX and local spot market prices; and other factors as the basis for these estimates. Variances between estimates and the actual amounts received are recorded when payment is received.

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

Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows therefrom.

Oil and Gas Properties

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

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

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

The company has made only one ceiling write-down in its 27-year history. That write down was made in 1986 after oil prices fell 51% and natural gas prices fell 45% between fiscal year end 1985 and 1986.

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

Oil and Gas Reserves

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

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

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

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

One measure of the life of the company s proved reserves can be calculated by dividing proved reserves at fiscal year end 2005 by production for fiscal year 2005. This measure yields an average reserve life of nine 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.

Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations requires that the company estimate the future cost of asset retirement obligations, discount that cost to its present value, and record a corresponding asset and liability in its Consolidated Balance Sheets. The values ultimately derived are based on many significant estimates, including future abandonment costs, inflation, market risk premiums, useful life, and cost of capital. The nature of these estimates requires the company to make judgments based on historical experience and future expectations. Revisions to the estimates may be required based on such things as changes to cost estimates or the timing of future cash outlays. Any such changes that result in upward or downward revisions in the estimated obligation will result in an adjustment to the related capitalized asset and corresponding liability on a prospective basis. A reconciliation of the company s asset retirement obligation liability is as follows:

	October 31,	
	2005	2004
Beginning asset retirement obligation	**$ 748,000**	$ 238,000
Accretion expense	**43,000**	(10,000)
Obligations incurred	**44,000**	23,000
Obligations settled	**(56,000)**	(6,000)
Change in estimate	**150,000**	503,000
Ending asset retirement obligation	**$ 929,000**	$ 748,000

Change in Accounting Principle

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, Accounting for Asset Retirement Obligations that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The company adopted SFAS No. 143 on November 1, 2002 and recorded an asset and related liability of $179,000 (using a 5% discount rate) and a cumulative effect on change in accounting principle on prior years of $72,000 (net of taxes of $28,000).

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 SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , to long-lived assets not included in oil and gas properties. Under SFAS No. 144, 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 SFAS No. 109, Accounting for Income Taxes , 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 Price Hedging

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

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

Hedging gains and losses are recognized as adjustments to gas sales as the hedged product is produced. The company had after tax hedging losses of $518,000 in fiscal 2005 and after tax hedging losses of $516,000 in fiscal 2004. Any hedge ineffectiveness, which was not material for the three years ended October 31, 2005, is immediately recognized in natural gas sales. Subsequent to October 31, 2005, the company closed its December 2005 and January 2006 contracts at expiration (120 MMbtu) with an after tax hedging loss of $227,000. The company currently has no open hedge positions.

The company has a hedging line of credit with its bank which is available, at the discretion of the company, to meet margin calls. To date, the company has not used this facility and maintains it only as a precaution related to possible margin calls. The maximum credit line is $2,000,000 with interest calculated at the prime rate. The facility is unsecured and has covenants that require the company to maintain $3,000,000 in cash or short term investments and prohibits unfunded debt in excess of $500,000. It expires on October 31, 2006.

Stock-Based Compensation

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, an amendment of SFAS No. 123 . Among other provisions, the statement amends the disclosure requirements of SFAS No. 123, Accounting for Stock-Based Compensation . Under current accounting rules the company elected to account for its stock-based employee compensation under the intrinsic value method established by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees .

The average fair value of each option granted was $8.93 in 2005 and $5.78 in 2003. No options were granted in 2004. All option grants were made with an exercise price equal to the market price on the date of grant. The fair value was estimated on the date of grant using the Black-Scholes option-pricing model with an expected average volatility of 48% in 2005 and 52% in 2003, a risk-free interest rate of 4% in 2005 and 3% in 2003, no expected dividends, and average expected terms of five years.

If compensation expense had been determined in accordance with the provisions of SFAS No. 123, the company s net income and per share amounts would have been reported as follows:

	Years Ended October 31,		
	2005	2004	2003
Net income as reported	**$ 5,229,000**	$ 3,650,000	$ 3,130,000
Fair value of stock-based compensation, net of tax	**(207,000)**	(282,000)	(428,000)
Pro forma net income	**$ 5,022,000**	$ 3,368,000	$ 2,702,000
Net income per share, basic:			
As reported	**$ .58**	$ .40	$ .35
Pro forma	**$ .55**	$ .37	$ .30
Net income per share, diluted:			
As reported	**$ .56**	$ .39	$ .35
Pro forma	**$ .54**	$ .36	$ .30

Table of Contents

Per Share Amounts

Basic income per share is computed using the weighted average number of shares outstanding. Diluted income 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, 2005 were 485,000.

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

	Year Ended October 31,								
	2005			2004			2003		
	Net Income	**Shares**	**Net Income Per Share**	Net Income	Shares	Net Income Per Share	Net Income	Shares	Net Income Per Share
Basic earnings per share	**$ 5,229,000**	**9,080,000**	**$ .58**	$ 3,650,000	9,036,000	$ .40	$ 3,130,000	8,869,000	$ .35
Effect of dilutive shares of common stock from stock options		**287,000**	**(.02)**		246,000	(.01)		173,000	
Diluted earnings per share	**$ 5,229,000**	**9,367,000**	**$ .56**	$ 3,650,000	9,282,000	$ .39	$ 3,130,000	9,042,000	$ .35

Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 153, Exchange of Non-monetary Assets . This statement is based on the principle that exchanges of non-monetary assets should be measured based on the fair value of the assets exchanges. SFAS 153 is effective for non monetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The company does not expect that the adoption of SFAS No. 153 will have an impact on the company s financial statements.

The Securities and Exchange Commission (SEC) recently issued guidance on the ways in which its full-cost rules interact with the accounting requirements that the FASB established for asset retirement obligations specifically, how SFAS No. 143, Accounting for Asset Retirement Obligations , interacts with the full-cost requirements in Rule 4-10 of Regulation S-X (Rule 4-10). The SEC s new guidance appears in Staff Accounting Bulletin (SAB) No. 106 issued in October 2004. The adoption of SAB No. 106 did not have an impact on the company s financial statements.

In March 2005, the FASB issued Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations An Interpretation of SFAS No. 143 , which clarifies the term conditional asset retirement obligation used in SFAS No. 143, Accounting for Asset Retirement Obligations , and specifically when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The adoption did not have an impact on the company s financial statements.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections , which replaces Accounting Principles Board Opinion No. 20, Accounting Changes and SFAS No. 3. SFAS 154 provides guidance on the accounting for and reporting of accounting changes and error corrections. It establishes retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The company does not expect that the adoption of SFAS No. 154 will have an impact on the company s financial statements.

In December 2004, the FASB issued SFAS No. 123 (Revised 2004), Share-Based Payment , that addresses the accounting for share-based payment transactions in which a company receives employee services in exchange for (a) equity instruments of the company or (b) liabilities that are based on the fair value of the company s equity instruments or that may be settled by the issuance of such equity instruments. SFAS No. 123R addresses all forms of share-based payment awards, including shares issued under employee stock purchase plans, stock options, restricted stock and stock appreciation rights. SFAS No. 123R eliminates the ability to account for share-based compensation transactions using APB Opinion No. 25, Accounting for Stock Issued to Employees , that was provided in Statement 123 as originally issued. Under SFAS No. 123R companies are required to record compensation expense for all share based payment award transactions measured at fair value. This statement is effective for fiscal years beginning after June 15, 2005. The company will implement SFAS 123R in the first quarter of the company s fiscal year beginning November 1, 2005. The company is currently evaluating the impact of this new standard, and estimates that the impact of applying the various provisions of SFAS No. 123R will result in an expense similar to the pro-forma effects reported elsewhere in this Annual Report on Form 10-K if all current unvested stock options vest on the scheduled dates and the assumptions in the Black-Scholes model remain the same.

(2) COMMON STOCK AND PREFERRED STOCK

The company has authorized 20,000,000 shares of $0.10 par value common stock of which 9,510,000 have been issued and are outstanding. 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.

On September 13, 2005, the company declared a 3-for-2 stock split to shareholders of record on September 26, 2005. Accordingly, 3,170,000 additional shares were issued on October 11, 2005. Common stock has been increased by the par value of the shares issued with a corresponding decrease in capital in excess of par value for all periods presented.

On March 24, 2004, the company declared a 3-for-2 stock split to shareholders of record on April 5, 2004. Accordingly, 2,006,000 additional shares were issued on April 20, 2004. Common stock has been increased by the par value of the shares issued with a corresponding decrease in capital in excess of par value.

On March 19, 2003, the company declared a 20% stock dividend to shareholders of record on April 2, 2003. On April 23, 2003, the company issued 656,000 shares of common stock in conjunction with this dividend. Accordingly, the fair value based on the quoted market price of the additional shares issued of $6,277,000 was charged to retained earnings and credited to common stock and capital in excess of par value. Cash payments were made to shareholders in lieu of fractional shares.

The company s 1997 Stock Option Plan (the Plan), as amended and restated effective October 25, 2001, authorizes the granting of incentive and nonqualified options to purchase shares of the company s common stock. 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. Plan activity is set forth below and has been adjusted for the 3-for-2 stock splits in fiscal 2005 and 2004 and the 20% stock dividend in 2003.

Table of Contents

	Years Ended October 31,					
	2005		2004		2003	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	**565,875**	**$ 7.11**	726,705	$ 4.74	258,930	$ 1.88
Granted	**33,750**	**8.93**			554,625	5.78
Exercised	**(61,686)**	**5.43**	(160,830)	1.88	(45,225)	1.25
Cancelled or forfeited	**(52,875)**	**6.01**			(41,625)	4.74
Outstanding at end of year	**485,064**	**$ 5.78**	565,875	$ 7.11	726,705	$ 4.74
Exercisable at end of year	**348,114**	**5.64**	267,048	5.55	254,763	3.21
Weighted average contractual life at end of year		**7.7**		7.8		7.2

The following table summarizes information about stock options outstanding at October 31, 2005:

	Outstanding			Exercisable	
Range of Exercise Prices	Number Outstanding at October 31, 2005	Weighted Average Remaining Contractual Life in Year	Weighted Average Exercise Price	Number Exercisable at October 31, 2005	Weighted Average Exercise Price
$3.09-$3.72	69,750	7.09	$ 3.46	40,313	$ 3.41
$5.93-$8.93	415,314	7.83	$ 6.17	307,801	$ 5.93
$3.09-$8.93	485,064	7.71	$ 5.78	348,114	$ 5.64

(3) COMMITMENTS

The company leases office facilities under an operating lease agreement which expires April 30, 2006. The lease agreement requires payments of $43,000 in 2005 and $21,500 in 2006. Total rental expense was $79,000 in 2005, $77,000 in 2004, and $73,000 in 2003. The company has no capital leases and no other operating lease commitments. At October 31, 2005, the company had remaining estimated capital commitments of $708,000 related to the South Texas project and $508,000 related to the north central Kansas project. Such costs, which include overhead, lease bonuses, land services and 3-D seismic, are expected to be funded over the next 12 to 15 months for both projects. Total costs incurred during 2005 for the South Texas project was $793,000 and $502,000 for the north central Kansas project.

(4) BENEFIT PLANS

Profit Sharing 401(k) Plan

The company has a 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 2005, 2004 and 2003 were $39,000, $35,000 and $25,000, respectively.

Other Company Benefits

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

(5) COMPREHENSIVE INCOME

Comprehensive income includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. The components of comprehensive income for the fiscal years ended October 31, 2005, 2004 and 2003 are as follows:

	October 31,		
	2005	2004	2003
Net income	**$ 5,229,000**	$ 3,650,000	$ 3,130,000
Other comprehensive income(loss):			
Change in fair value of derivatives	**182,000**	(857,000)	199,000
Income tax (expense) benefits	**(51,000)**	240,000	(56,000)
Total comprehensive income	**$ 5,360,000**	$ 3,033,000	$ 3,273,000

The following table sets forth a reconciliation of the company s accumulated gain(loss) on derivatives for the fiscal years ended October 31, 2005, 2004 and 2003.

	October 31,		
	2005	2004	2003
Accumulated gain (loss) on derivatives:			
Balance beginning of period	**$ (437,000)**	$ 180,000	$ 37,000
Realization of hedging gain (losses)	**10,000**	(176,000)	(9,000)
Net unrealized gain (losses) on price hedge contracts	**121,000**	(441,000)	152,000
Balance end of period	**$ (306,000)**	$ (437,000)	$ 180,000

(6) INCOME TAXES

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

At October 31, 2005 the company had $655,000 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,		
	2005	2004	2003
Current	**$ 715,000**	$ 114,000	$ 173,000
Deferred	**1,318,000**	1,306,000	1,016,000
Total income tax expense	**$ 2,033,000**	$ 1,420,000	$ 1,189,000

Table of Contents

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

	Years Ended October 31,		
	2005	2004	2003
Federal statutory income tax rate	**34%**	34%	34%
State income taxes	**2**	2	2
Percentage depletion	**(8)**	(8)	(8)
	28%	28%	28%

The principal sources of temporary differences resulting in deferred tax assets and tax liabilities at October 31, 2005 and 2004 are as follows:

	October 31,	
	2005	2004
Deferred tax assets:		
Gain on property sales	**$ 564,000**	$ 505,000
Total deferred tax assets	**564,000**	505,000
Deferred tax liabilities:		
Intangible drilling, leasehold and other exploration costs capitalized for financial reporting purposes but deducted for tax purposes	**(5,760,000)**	(4,714,000)
State taxes and other	**(782,000)**	(396,000)
Total deferred tax liabilities	**(6,542,000)**	(5,110,000)
Net deferred tax liability	**$ (5,978,000)**	$ (4,605,000)

(7) EXCLUSIVE LICENSE AGREEMENT OBLIGATION

On September 1, 2000, the company acquired an unrestricted, exclusive license for patented technology. The initial license term was 10 years and includes an option for the company to extend the term to the remaining life of the patents. The licensor will receive a net 8.3% carried interest in any installation of the technology. The license purchase price was $1,115,000, of which $818,000 has been paid. The balance, which is due in four remaining annual increments of $93,750, is recorded at 10% present value. The related assets are being amortized over 10 years on a straight-line basis. If the option to extend the license after the initial 10-year term is exercised, the cost will be $93,750 per year to the expiration of the last patent.

	October 31, 2005	
	Gross Carrying Amount	Accumulated Amortization
Amortized intangible assets:		
Exclusive license agreement	$ 699,000	$ 361,000

Aggregate amortization expense:	
For the year ended October 31, 2005	$ 70,000

Estimated future amortization expense:	
For the year ended October 31, 2006	$ 70,000
For the year ended October 31, 2007	70,000
For the year ended October 31, 2008	70,000
For the year ended October 31, 2009	70,000
For the year ended October 31, 2010	58,000
Total	$ 338,000

This amortizable intangible asset is an exclusive license agreement related solely to the company s patented liquid lift system for low pressure gas wells.

The company reviews the value of its intangible assets in accordance with SFAS No. 142, Goodwill and Other Intangible Assets , which requires that it evaluate these assets for impairment whenever events or changes in business circumstances indicate that the carrying amount of the assets may not be fully recoverable or that the useful lives of these assets are no longer appropriate.

At October 31, 2005, this amortizable intangible asset had a net book value of $338,000. The value of this asset is believed to be realizable based on the company s estimation of future cash flows from application of the company s patented liquid lift system. The company s impairment test compares the estimated undiscounted future net cash flows related to this asset with the related net capitalized costs of the asset at the end of each period. If the net capitalized cost exceeds the undiscounted future net cash flows, the cost of the asset is written down to estimated fair value. As of October 31, 2005, the company has not recorded an impairment write-down for this asset. The estimated undiscounted value of future net cash flows is derived from estimates of proved reserve values.

(8) SUPPLEMENTARY OIL AND GAS INFORMATION

Capitalized Costs

	October 31,		
	2005	2004	2003
Unevaluated properties not being amortized	**$ 3,452,000**	$ 2,174,000	$ 2,075,000
Properties being amortized	**36,121,000**	30,072,000	23,082,000
Accumulated depreciation, depletion and amortization	**(15,022,000)**	(12,737,000)	(11,096,000)
Total capitalized costs	**$ 24,551,000**	$ 19,509,000	$ 14,061,000

Table of Contents

Unevaluated Oil and Gas Properties

Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until they are evaluated. The following table shows, by category of cost and date incurred, the unevaluated oil and gas property costs (net of transfers to the full cost pool and sales proceeds) excluded from the amortization computation:

Net Costs Incurred During Periods Ended:	Unevaluated Properties At October 31, 2005
October 31, 2005	$ 2,415,000
October 31, 2004	709,000
October 31, 2003	234,000
Prior	94,000
	$ 3,452,000

Unevaluated properties consist primarily of lease acquisition and maintenance costs. 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

	Years Ended October 31,		
	2005	2004	2003
Property acquisition costs net of divestiture proceeds:			
Proved	**$ 81,000**	$ 526,000	$
Unproved	**2,092,000**	346,000	385,000
Exploration costs	**834,000**	1,791,000	4,067,000
Development costs	**4,170,000**	3,926,000	822,000
Total before asset retirement obligation	**$ 7,177,000**	$ 6,589,000	$ 5,274,000
Total including asset retirement obligation	**$ 7,327,000**	$ 7,089,000	$ 5,440,000

Major Customers and Operating Region

The company operates exclusively within the United States. Except for cash investments, all of the company s assets are employed in, and all its revenues are derived from, the oil and gas industry. The company had sales in excess of 10% of total revenues to oil and gas purchasers as follows: Duke Energy 40% in 2005, 40% in 2004, and 49% in 2003; Enogex, Inc. 9% in 2005, 10% in 2004 and 10% in 2003.

Oil and Gas Reserve Data (Unaudited)

Independent petroleum engineers estimated proved reserves for the company s properties which represented approximately 63% in 2005, 61% in 2004, and 64% in 2003 of total estimated future net revenues. The remaining reserves were estimated by the company. 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 $55.59, $50.43 and $28.64 per barrel for oil and $10.26, $5.84, and $3.99 per Mcf for gas in 2005, 2004, and 2003, respectively. Estimated future costs were calculated assuming continuation of costs and economic conditions at the reporting date.

41

Table of Contents

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

	2005		2004		2003	
	Gas(Mcf)	**Oil(bbls)**	Gas(Mcf)	Oil(bbls)	Gas(Mcf)	Oil(bbls)
Proved reserves:						
Balance, November 1	**15,273,000**	**407,000**	13,786,000	385,000	9,415,000	337,000
Revisions of previous estimates	**(889,000)**	**(6,000)**	68,000	39,000	(220,000)	35,000
Extensions and discoveries	**2,962,000**	**22,000**	2,999,000	23,000	5,867,000	51,000
Purchases of reserves in place			130,000	1,000	178,000	
Sales of reserves in place					(5,000)	(3,000)
Production	**(1,830,000)**	**(37,000)**	(1,710,000)	(41,000)	(1,449,000)	(35,000)
Balance, October 31	**15,516,000**	**386,000**	15,273,000	407,000	13,786,000	385,000
Proved developed reserves:						
Beginning of period	**13,993,000**	**374,000**	13,786,000	385,000	8,459,000	298,000
End of period	**13,603,000**	**381,000**	13,993,000	374,000	13,786,000	385,000

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

	2005	2004	2003
Future cash inflows	**$ 180,726,000**	$ 109,703,000	$ 66,043,000
Future production and development costs	**(43,848,000)**	(32,091,000)	(20,878,000)
Future income tax expense	**(36,054,000)**	(19,965,000)	(11,094,000)
Future net cash flows	**100,824,000**	57,647,000	34,071,000
10% discount factor	**(41,337,000)**	(24,788,000)	(12,930,000)
Standardized measure of discounted future net cash flows	**$ 59,487,000**	$ 32,859,000	$ 21,141,000

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

	2005	2004	2003
Balance, November 1	**$ 32,859,000**	$ 21,141,000	$ 14,066,000
Sales of oil and gas produced, net of production costs	**(10,384,000)**	(7,292,000)	(5,886,000)
Net changes in prices and production costs	**29,821,000**	14,919,000	2,071,000
	15,804,000	8,617,000	11,436,000

Extensions and discoveries, net of future development and production costs			
Changes in future development costs	**(1,692,000)**	(224,000)	(54,000)
Previously estimated development costs incurred during the period	**2,248,000**	304,000	467,000
Revisions of previous quantity estimates, timing, and other	**(2,962,000)**	(2,129,000)	77,000
Purchases of reserves in place		465,000	441,000
Sales of reserves in place			(66,000)
Accretion of discount	**3,286,000**	2,114,000	1,407,000
Net change in income taxes	**(9,493,000)**	(5,056,000)	(2,818,000)
Balance, October 31	**$ 59,487,000**	$ 32,859,000	$ 21,141,000

Table of Contents

(9) QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following is a tabulation of the company s unaudited quarterly operating results for fiscal 2003, 2004 and 2005:

	Total Revenue	Income Before Income Taxes	Net Income	Basic Net Income Per Share	Diluted Net Income Per Share
Fiscal 2003:					
First Quarter	$ 1,791,000	$ 852,000	$ 685,000	$ 0.09	$ 0.09
Second Quarter	1,684,000	697,000	502,000	0.06	0.06
Third Quarter	2,243,000	1,107,000	797,000	0.09	0.09
Fourth Quarter	2,773,000	1,591,000	1,146,000	0.11	0.11
	$ 8,491,000	$ 4,247,000	$ 3,130,000	$ 0.35	$ 0.35
Fiscal 2004:					
First Quarter	$ 2,850,000	$ 1,618,000	$ 1,165,000	$ 0.13	$ 0.12
Second Quarter	2,273,000	1,092,000	786,000	0.08	0.08
Third Quarter	2,439,000	1,120,000	806,000	0.09	0.09
Fourth Quarter	2,752,000	1,240,000	893,000	0.10	0.10
	$ 10,314,000	$ 5,070,000	$ 3,650,000	$ 0.40	$ 0.39
Fiscal 2005:					
First Quarter	$ 2,606,000	$ 1,263,000	$ 909,000	$ 0.10	$ 0.10
Second Quarter	3,202,000	1,639,000	1,180,000	0.13	0.13
Third Quarter	3,665,000	1,961,000	1,412,000	0.16	0.15
Fourth Quarter	4,484,000	2,399,000	1,728,000	0.19	0.18
	$ 13,957,000	$ 7,262,000	$ 5,229,000	$ 0.58	$ 0.56

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
CREDO PETROLEUM CORPORATION AND SUBSIDIARIES

To the Board of Directors and Stockholders
CREDO Petroleum Corporation and Subsidiaries

We have audited the consolidated balance sheets of CREDO Petroleum Corporation and subsidiaries as of October 31, 2005 and 2004, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended October 31, 2005. These financial statements are the responsibility of the company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of CREDO Petroleum Corporation and subsidiaries as of October 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended October 31, 2005, in conformity with U.S. generally accepted accounting principles.

/s/ HEIN & ASSOCIATES LLP

HEIN & ASSOCIATIONS LLP

Denver, Colorado
January 6, 2006

Table of Contents

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we evaluated the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act) as of October 31, 2005. On the basis of this review, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures are designed, and are effective, to give reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and to ensure that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, in a manner that allows timely decisions regarding required disclosure. There were no changes in the company s internal controls over financial reporting that occurred in the fourth fiscal quarter of 2005 that materially affected or were reasonably likely to materially affect, its internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

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 close 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 March 23, 2006 and is hereby incorporated by reference.

Table of Contents

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements:
- Consolidated Balance Sheets October 31, 2005 and 2004
- Consolidated Statements of Operations Three Years ended October 31, 2005
- Consolidated Statements of Shareholders Equity Three Years ended October 31, 2005
- Consolidated Statements of Cash Flows Three Years ended October 31, 2005
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm

(2) Financial Statement Schedules:

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

(b) Exhibits. The following exhibits are filed with or incorporated by reference into this report on Form 10-K.

3(a)(i) & 4(a)	Articles of Incorporation of CREDO Petroleum Corporation (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(ii)	Articles of Amendment of Articles of Incorporation, dated March 9, 1982 (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(iii)	Articles of Amendment of Articles of Incorporation, dated October 28, 1982 (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(iv)	Articles of Amendment of Articles of Incorporation dated April 18, 1984 (incorporated by reference to Form 10-K dated October 31, 1984).
3(a)(v)	Articles of Amendment of Articles of Incorporation dated April 18, 1984 (incorporated by reference to Form 10-K dated October 31, 1984).
3(a)(vi)	Articles of Amendment of Articles of Incorporation dated April 2, 1985 (incorporated by reference to Form 10-K dated October 31, 1985).
3(a)(vii)	Articles of Amendment of Articles of Incorporation dated March 25, 1986 (incorporated by reference to Form 10-K dated October 31, 1986).
3(a)(viii)	Articles of Amendment of Articles of Incorporation dated March 24, 1988 (incorporated by reference to Form 10-K dated October 31, 1989).
3(a)(ix)	Articles of Amendment to Articles of Incorporation dated May 11, 1990.
3(b)(i)	By-Laws of CREDO Petroleum Corporation, as amended October 30, 1986 (incorporated by reference to Form 10-K dated October 31, 1986).
3(b)(ii)	Amendment to Article X of CREDO Petroleum Corporation s By-Laws dated March 24, 1988 (incorporated by reference to the company s definitive proxy dated February 5, 1988).
4(i)	Shareholders Rights Plan, dated April 11, 1989.
4(ii)	Amendment to Shareholders Rights Plan, dated February 24, 1999 (incorporated into Part II of the company s Form 10-QSB dated January 31, 1999).
10(a)	CREDO Petroleum Corporation Non-qualified Stock Option Plan, dated January 13, 1981 (incorporated by reference to Amendment No. 1 to Form S-1 dated February 2, 1981).
10(b)	CREDO Petroleum Corporation Incentive Stock Option Plan, dated October 2, 1981 (incorporated by reference to the company s definitive proxy statement, dated January 22, 1982).
10(c)	Model of Director and Officer Indemnification Agreement provided for by Article X of CREDO Petroleum Corporation s By-Laws (incorporated by reference to Form 10-K dated October 31, 1987).
10(d)	

	CPC Exclusive License Agreement, dated September 1, 2000 (incorporated by reference to Form 10-KSB dated October 31, 2000).
10(e)	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).

46

Table of Contents

14.1	Code of Business Conduct and Ethics (incorporated by reference to Form 10-KSB dated October 31, 2004).
21	CREDO Petroleum Corporation (a Colorado 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 6, 2006.
31.1 *	Certification by Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2 *	Certification by Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
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 herewith)

* Filed with this Form 10-K.

Table of Contents

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 27, 2006.

CREDO PETROLEUM CORPORATION
(Registrant)

By: /s/ James T. Huffman
James T. Huffman,
Chairman of the Board of Directors,
President 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 27, 2006	/s/ James T. Huffman James T. Huffman	Chairman of the Board of Directors, President, Treasurer and Chief Executive Officer (Principal Executive Officer)
January 27, 2006	/s/ David W. Vreeman David W. Vreeman	Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
January 27, 2006	/s/ William N. Beach William N. Beach	Director
January 27, 2006	/s/ Clarence H. Brown Clarence H. Brown	Director
January 27, 2006	/s/ Oakley Hall Oakley Hall	Director
January 27, 2006	/s/ William F. Skewes William F. Skewes	Director, General Counsel
January 27, 2006	/s/ Richard B. Stevens Richard B. Stevens	Director

Table of Contents

Exhibit Index

Exhibits. The following exhibits are filed with or incorporated by reference into this report on Form 10-K.

3(a)(i) & 4(a)	Articles of Incorporation of CREDO Petroleum Corporation (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(ii)	Articles of Amendment of Articles of Incorporation, dated March 9, 1982 (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(iii)	Articles of Amendment of Articles of Incorporation, dated October 28, 1982 (incorporated by reference to Form 10-K dated October 31, 1982).
3(a)(iv)	Articles of Amendment of Articles of Incorporation dated April 18, 1984 (incorporated by reference to Form 10-K dated October 31, 1984).
3(a)(v)	Articles of Amendment of Articles of Incorporation dated April 18, 1984 (incorporated by reference to Form 10-K dated October 31, 1984).
3(a)(vi)	Articles of Amendment of Articles of Incorporation dated April 2, 1985 (incorporated by reference to Form 10-K dated October 31, 1985).
3(a)(vii)	Articles of Amendment of Articles of Incorporation dated March 25, 1986 (incorporated by reference to Form 10-K dated October 31, 1986).
3(a)(viii)	Articles of Amendment of Articles of Incorporation dated March 24, 1988 (incorporated by reference to Form 10-K dated October 31, 1989).
3(a)(ix)	Articles of Amendment to Articles of Incorporation dated May 11, 1990.
3(b)(i)	By-Laws of CREDO Petroleum Corporation, as amended October 30, 1986 (incorporated by reference to Form 10-K dated October 31, 1986).
3(b)(ii)	Amendment to Article X of CREDO Petroleum Corporation s By-Laws dated March 24, 1988 (incorporated by reference to the company s definitive proxy dated February 5, 1988).
4(i)	Shareholders Rights Plan, dated April 11, 1989.
4(ii)	Amendment to Shareholders Rights Plan, dated February 24, 1999 (incorporated into Part II of the company s Form 10-QSB dated January 31, 1999).
10(a)	CREDO Petroleum Corporation Non-qualified Stock Option Plan, dated January 13, 1981 (incorporated by reference to Amendment No. 1 to Form S-1 dated February 2, 1981).
10(b)	CREDO Petroleum Corporation Incentive Stock Option Plan, dated October 2, 1981 (incorporated by reference to the company s definitive proxy statement, dated January 22, 1982).
10(c)	Model of Director and Officer Indemnification Agreement provided for by Article X of CREDO Petroleum Corporation s By-Laws (incorporated by reference to Form 10-K dated October 31, 1987).
10(d)	CPC Exclusive License Agreement, dated September 1, 2000 (incorporated by reference to Form 10-KSB dated October 31, 2000).
10(e)	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).

Table of Contents

14.1	Code of Business Conduct and Ethics (incorporated by reference to Form 10-KSB dated October 31, 2004).
21	CREDO Petroleum Corporation (a Colorado 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 6, 2006.
31.1 *	Certification by Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2 *	Certification by Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
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 herewith)

* Filed with this Form 10-K.