QUEST RESOURCE CORPORATION

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QUEST
Resource Corporation

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2004 Annual Report

QUEST RESOURCE
CORPORATION
OKLAHOMA CITY,
OKLAHOMA

September 27, 2004

To Our Shareholders:

The fiscal year ended May 31, 2004 has been another year of unprecedented growth for Quest Resource Corporation. As a result of our acquisition of the Cherokee Basin gas properties and pipeline assets of Devon Energy Corporation on December 22, 2003 for approximately $126 million, Quest has more than tripled in size since last year and is now the dominant gas producer in the Cherokee Basin of southeastern Kansas and northeastern Oklahoma. This acquisition was accomplished through a series of sophisticated financial and organizational transactions that resulted in the consolidation of Quest's Cherokee Basin assets into a new Quest subsidiary—Quest Cherokee, LLC. In order to successfully integrate such a significant acquisition into our existing operations, we have increased our employee force to about 160 personnel. In the nine months since the acquisition from Devon, we believe that we have been successful in accomplishing this integration and have accelerated our ongoing drilling program to take advantage of the increased undeveloped acreage controlled by Quest. All of this has resulted in the impressive financial results achieved for the 2004 fiscal year.

Highlights of these financial results include Total Revenue of $30.0 million for fiscal year 2004 as compared to $8.1 (restated) for the 2003 fiscal year. Earnings before interest, income taxes and depreciation, depletion and amortization expense (EBITDA) was $17.1 million for the 2004 fiscal year as compared to $4.2 million for 2003, or $1.10 and $0.37 per diluted share, respectively. Proved gas reserves also increased dramatically from 28 Bcf in 2003 to over 133 Bcf as of the end of the 2004 fiscal year. The estimated Present Value of Future Net Cash Flow discounted at 10% increased from $70 million at the end of the 2003 fiscal year to approximately $318 million as of May 31, 2004.

Of course all of this tremendous growth does not come without growing pains. Shortly after completing the acquisition of assets from Devon, it became clear to management that the size and complexity of our operations had outgrown the capabilities of our internal financial and accounting staff and of our independent accounting firm. As a result, we had to temporarily suspend our filings with the Securities and Exchange Commission. In response, we hired a new Chief Financial Officer with significant public company experience in the oil and gas industry as well as additional accounting personnel and other administrative staff. We also retained a new independent auditor. We have recently completed the restatement of our 2003 financial statements and have filed all of our past-due SEC filings. We appreciate your patience during this time and believe that we now have the necessary personnel, controls and procedures to successfully manage the financial and accounting aspects of our business.

One of the first major projects under taken by our expanded corporate staff was the refinancing of Quest Cherokee's credit facilities in July 2004. The Company entered into a new syndicated credit facility with UBS, AG as administrative agent that includes a $120 million term loan and a $20 million revolving credit facility. This additional funding has allowed Quest Cherokee to move forward aggressively with its drilling and pipeline construction programs and to continue other strategic acquisitions.

We can reflect back on the 2004 fiscal year as a year of phenomenal growth that has positioned Quest for on-going expansion that should continue increasing our profitability and shareholder equity for the long term benefit of our shareholders and employees. Details of our latest fiscal year are available for your review in this Annual Report which includes Form 10-KSB that has been filed with the Securities and Exchange Commission for the year ended May 31, 2004.

Sincerely,

Douglas L. Lamb
President

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

FORM 10-KSB

(Mark One)

[X] Annual report under Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended May 31, 2004.

[ ] Transition report under Section 13 or 15(d) of the Securities Exchange Act of 1934 (no fee required) for the transition period from ____________ to ______________.

Commission file number: 0-17371

QUEST RESOURCE CORPORATION

(Name of Small Business Issuer in Its Charter)

Nevada	**88-0182808**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

9520 N. May, Suite 300, Oklahoma City, Oklahoma 73120
(Address of Principal Executive Offices)(Zip Code)

Issuer's Telephone Number: **405-488-1304**

Securities Registered Under Section 12(b) of the Exchange Act: **None**

Securities Registered Under Section 12(g) of the Exchange Act: **Common Stock, $0.001 Par Value**
Title of Class

Check whether the issuer: (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X No

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B is not contained in this form, and no disclosure will 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-KSB or any amendment to this Form 10-KSB [ ].

The issuer's revenues for the year ended May 31, 2004 were $30,011,000. The aggregate market value of the voting stock held by non-affiliates computed by reference to the last reported sale of the issuer's common stock on September 16, 2004 at $4.40 per share was $30,979,929. This figure assumes that only the directors and officers of the Company, their spouses and controlled corporations were affiliates.

There were 14,112,694 shares outstanding of the issuer's common stock as of September 16, 2004.

DOCUMENTS INCORPORATED BY REFERENCE

The definitive proxy statement relating to the issuer's 2004 Annual Meeting of Stockholders is incorporated by reference in Part III to the extent described therein.

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PART I

ITEMS 1. AND 2. DESCRIPTION OF BUSINESS AND PROPERTIES

General

Quest Resource Corporation ("the Company") is an independent energy company with an emphasis on the acquisition, exploration, development, production, and transportation of natural gas (coal bed methane) in a ten county region in the Cherokee Basin of southeastern Kansas and northeastern Oklahoma. The Company also owns and operates a natural gas gathering pipeline network of approximately 900 miles in length within this basin. The Company's main focus is upon the development of the coal bed methane gas reserves in the Company's pipeline network region and upon the continued enhancement of the pipeline system and supporting infrastructure. Unless otherwise indicated, references to the Company include the Company's operating subsidiaries.

This report on Form 10-KSB contains forward-looking statements regarding, among other topics, the Company's growth strategies, anticipated trends in the Company's business and its future results of operations, estimated future net revenues from natural gas and oil reserves and the present value thereof, planned capital expenditures, increases in natural gas production and development activities, and the Company's financial position, business strategy and other plans and objectives for future operations. Although the Company believes that the expectations reflected in these forward looking statements are reasonable, there can be no assurance that the actual results or developments anticipated by the Company will be realized or, even if substantially realized, that they will have the expected effects on its business or operations. The Company assumes no obligation to update these statements. See Item 6. "Management's Discussion and Analysis or Plan of Operation - Cautionary Statements for Purposes of the 'Safe Harbor' Provisions of the Private Securities Litigation Reform Act of 1995" for a more detailed listing of the factors that may affect these forward looking statements.

As disclosed in the Company's Form 10-KSB/A (Amendment No. 2) for 2003 filed with the SEC on September 10, 2004, the Company has restated its financial statements for the fiscal years ended May 31, 2003 and 2002, and for the fiscal quarters ended August 31, 2002, November 30, 2002, February 28, 2003 and August 31, 2003. The Company determined that the restatements were necessary after an internal review of financial statements and supporting documentation determined that certain transactions were recorded incorrectly. In addition, the Company either failed to adopt or improperly adopted various accounting pronouncements for the fiscal year ended May 31, 2003. See Item 6. "Management's Discussion and Analysis or Plan of Operation" and Note 2 to the Consolidated Financial Statements included in this report.

Business Strategy

The Company's objective is to achieve a substantial enhancement of shareholder value by increasing cash flow, profitability and net asset value. To accomplish this objective, the Company is pursuing the following business strategy:

- focusing exploration and drilling efforts in the Cherokee Basin of southeastern Kansas and northeastern Oklahoma;
- accumulating leasehold acreage positions in the Cherokee Basin—management believes that the Cherokee Basin remains highly fragmented and that additional acquisition opportunities exist;
- operating its properties whenever possible—the Company currently operates over 90% of the natural gas and oil properties in which it has an interest;
- increasing third party volumes on its gathering and pipeline systems; and
- exploring other basins for coalbed methane opportunities

Management believes that this strategy is enhanced by the Company's competitive strengths, which include:

- low overhead costs,
- cost efficient operations,
- an inventory of good drilling locations,
- management and key operations personnel that are experienced and dedicated, and

- a proven track record as an effective, low cost developer and producer of coalbed methane natural gas.

Additional staff and the Company's new credit facilities have further enhanced the ability of the Company to compete in making acquisitions that are strategic to continued growth.

Recent Developments

The Restructuring

Immediately prior to the acquisition of the Devon properties (see "Devon Asset Acquisition"), the Company's Cherokee Basin natural gas and oil leases were held by two subsidiaries, Quest Oil & Gas Corporation ("QOG") and STP Cherokee, Inc. ("STP") and the Company's pipelines were held by four subsidiaries, Ponderosa Gas Pipeline Company ("PGPC"); STP; Producers Service, Incorporated ("PSI"); and J-W Gas Gathering, L.L.C. ("J-W Gas") and any vehicles and construction equipment were held by two subsidiaries, Quest Energy Service, Inc. ("QES") and STP. In addition, STP owned assets in Texas, Kentucky and Oklahoma that were outside the Cherokee Basin and the employees were split between QES and STP. All of these subsidiaries are directly or indirectly wholly-owned by the Company.

In order to facilitate the financing of the acquisition of the Devon properties, the Company restructured its operations to consolidate all of its Cherokee Basin assets (including the acquired Devon assets) into a single entity that did not have any assets outside the Cherokee Basin and that did not have any employees. The Company formed Quest Cherokee, LLC ("Quest Cherokee") in order to carryout the restructuring and the acquisition from Devon. On December 22, 2003, Quest Cherokee was formed as a Delaware limited liability company by QES; STP; PGPC; QOG; PSI; and J-W Gas (collectively hereafter referred to as the "Quest Group"). The Quest Group then contributed to Quest Cherokee their natural gas and oil leases located in the Cherokee Basin and the related wells, gas gathering pipelines, equipment and related assets in exchange for an ownership interest in Quest Cherokee. Immediately after giving effect to such contributions, Quest Cherokee was wholly-owned by the Company indirectly through its subsidiaries. The gas gathering pipeline assets, including those acquired from Devon, were assigned to Bluestem Pipeline, LLC ("Bluestem"), a newly formed, wholly-owned subsidiary of Quest Cherokee.

As part of the restructuring, QES entered into an operating and management agreement with Quest Cherokee to manage the day to day operations of Quest Cherokee in exchange for a monthly manager's fee of $292,000 plus the reimbursement of costs associated with field employees, first level supervisors, exploration, development and operation of the properties and certain other direct charges. The Company consolidated all of its employees into QES.

After giving effect to the restructuring, STP continues to own properties located in Kentucky, Texas and Oklahoma outside of the Cherokee Basin, and QES and STP own certain equipment used at the corporate headquarters offices.

As part of the restructuring, Quest Cherokee assumed all of the Company's and its subsidiaries existing indebtedness for borrowed money. The indebtedness to Wells Fargo Bank and Wells Fargo Energy Capital was refinanced in connection with the financing transactions discussed below.

Devon Asset Acquisition

On December 10, 2003, the Company entered into an asset purchase agreement with Devon Energy Production Company, L.P. and Tall Grass Gas Services, LLC (collectively "Devon") to acquire certain natural gas properties located in Kansas and Oklahoma for a total consideration of $126 million, subject to certain purchase price adjustments. At the time of closing, Devon had not received consents to the assignment of certain of the leases from the lessors on natural gas leases with an allocated value of approximately $12.3 million. As a result, Quest Cherokee and Devon entered into a Holdback Agreement pursuant to the terms of which Quest Cherokee paid approximately $113.4 million of the purchase price at the closing and agreed to pay the allocated value of the remaining properties at such time as Devon received the consents to assignment for those leases. Subsequent to closing, Quest Cherokee paid approximately $9.6 million in February 2004 and $2.6 million in May 2004. As of May 31, 2004, approximately $600,000 was included on the balance sheet as acquisition holdback payable pending final review. This amount was classified as a non-current liability since the payment will be funded with long-term financing. The acquisition was finalized on December 22, 2003. At the closing, the Company transferred all of its rights and obligations under the asset purchase agreement to Quest Cherokee. At the time of acquisition, the acquired assets had approximately 95.9 Bcfe of estimated proved reserves, 91.7 Bcfe of estimated probable reserves and 72.2 Bcfe of estimated possible reserves. The assets included approximately 372,000 gross (366,000 net) acres of natural gas leases, 418 gross (325 net) natural gas wells and 207 miles of gas gathering pipelines. At the time of acquisition, the Devon assets were producing an average of approximately 19,600 mcf per day. See the Current Report on Form 8-K filed by the Company on January 6, 2004 for additional information regarding the Devon acquisition.

ArcLight Transaction

As part of the financing for the acquisition of properties from Devon, Quest Cherokee issued a $51 million subordinated promissory note to Cherokee Energy Partners LLC, a wholly owned subsidiary of ArcLight Energy Partners Fund I, L.P. ("ArcLight"). In connection with the purchase of the subordinated promissory note, the original limited liability company agreement for Quest Cherokee was amended and restated to, among other things, provide for Class A units and Class B units of membership interest, and ArcLight acquired all of the Class A units of Quest Cherokee in exchange for $100. The existing membership interests in Quest Cherokee owned by the Company's subsidiaries were converted into all of the Class B units.

Although management of the Company is responsible for the day-to-day operations of Quest Cherokee, all major decisions regarding Quest Cherokee must be approved by Quest Cherokee's board of managers. The holders of the Class A units (as a class) and the Class B units (as a class) are each entitled to appoint two managers. In general, the vote of all the managers is required to approve any matter voted on by the managers. If there is a conflict of interest, then the managers that have the conflict of interest will not be entitled to vote on the matter. The vote of a majority of each of the Class A units and Class B units is required to approve any matter submitted to a vote of the members. As a result of these voting provisions, the Board of Directors and management of Quest Resource Corporation do not have the ability to control all of the decisions with respect to the operation of Quest Cherokee.

See Item 6. "Management's Discussion and Analysis or Plan of Operation—Capital Resources and Liquidity—ArcLight Transaction" for additional information regarding the terms of ArcLight's investment in the Company.

Bank One Credit Facilities

In connection with the December 22, 2003 Devon asset acquisition, the previous credit facilities with Wells Fargo Bank Texas, N.A. and Wells Fargo Energy Capital, Inc. were retired. The Company, through its subsidiary Quest Cherokee, entered into a Credit Agreement consisting of a three year $200 million senior revolving loan (the "Revolving Credit Agreement") and a five year $35 million senior term second lien secured loan (the "Term Loan Agreement") arranged and syndicated by Banc One Capital Markets, Inc. and with Bank One, NA, as agent. The Revolving Credit Agreement provided for an initial borrowing base of $57 million, which amount was increased to $70 million upon delivery to the administrative agent of a certificate evidencing that third party consents had been obtained for the assignment of certain natural gas leases from Devon. For more information regarding the Bank One credit facilities, see Item 6. "Management's Discussion and Analysis of Financial Condition or Plan of Operation–Capital Resources and Liquidity–Bank One Credit Facilities."

Subsequent to May 31, 2004, the Bank One credit facilities were refinanced with a new credit facility from UBS. See Item 6. "Management's Discussion and Analysis of Financial Condition or Plan of Operation–Capital Resources and Liquidity–UBS Credit Facility."

Other Acquisitions

Since the beginning of the 2004 fiscal year, the Company has completed two other significant acquisitions.

<u>Acquisition of Natural Gas Producing Assets and Pipeline in the Cherokee Basin.</u> Effective June 1, 2003, the Company closed the acquisition of natural gas producing properties, natural gas pipelines and a fleet of trucks and well service equipment, all of which are located in the southeastern Kansas portion of the geological region known as the Cherokee Basin. Approximately 15,000 acres of natural gas properties containing an estimated 3.8 Bcf of net proved natural gas reserves were acquired by QOG for approximately $2.0 million in cash, which was paid to entities owned by

James R. Perkins and E. Wayne Willhite. These properties consisted of approximately 53 natural gas leases in Chautauqua, Montgomery and Elk Counties of southeastern Kansas.

In a related transaction, another Company subsidiary, PGPC, acquired all of the stock of PSI, which included PSI's wholly owned subsidiary J-W Gas, in exchange for 500,000 shares of the Company's common stock. PSI and J-W Gas owned, or controled the operational rights to, approximately 274 miles of natural gas gathering pipelines. JW also owned a fleet of trucks and well servicing equipment, and a shop building in Howard, Kansas.

The acquisition of these two companies and the natural gas property assets greatly enhanced the Company's natural gas pipeline assets into a network of about 600 miles and extended the Company's core area for gas production into the western region of the Cherokee Basin. This acquisition also brought into the Company's workforce 13 highly experienced staff and field personnel that are making a valuable contribution to the Company's productivity and future growth. These assets are collectively referred to as the "Perkins/Willhite acquisition." In connection with the formation of Quest Cherokee, these assets were transferred to Quest Cherokee.

Acquisition of Kentucky Coalbed Methane Leases. On July 18, 2003 the Company entered into a coalbed methane lease with Alcoa Fuels, Inc., a subsidiary of Alcoa Inc. (NYSE: AA), for more than 63,200 net acres in western Kentucky.

The property is located in Union, Crittenden and Webster Counties in western Kentucky and represents a significant expansion in the geographic area in which the Company operates. Prior to the execution of this lease, the Company's operations had been limited to a ten county region in the Cherokee Basin in southeastern Kansas and northeastern Oklahoma. Although the distance from the Company's current operations will represent a logistical challenge, management believes that its technical team's experience and dedication will provide the Company with the necessary resources to successfully expand its operations into this new region.

The lease has an initial term of one year during which the Company will conduct a technical study to determine the feasibility of the development of the leased property. At the end of the first year, the Company has an option to extend the lease for an additional four years upon the payment of an agreed upon amount. Thereafter, the Company will generally be entitled to continue leasing the property for so long as the Company is continuously developing the leased premises at the rate of not less than 25 wells per year until the property is fully developed on 160 acre spacing (approximately 400 wells). If the Company ceases to continuously develop the property, it will be entitled to continue leasing the portion of the property that has been developed for so long as it is producing coalbed methane from the developed property is in paying quantities. Subsequent to May 31, 2004, the Company obtained a five month extension of the initial one year term of the lease and agreed to commence drilling the first well no later than October 6, 2004. If the Company does not commence drilling the first well by October 6, 2004 the five month extension terminates and the Company has no further obligations to develop this property.

Company Operations

The Company business operations consist of natural gas and oil exploration and production activities, the operation of a pipeline network and related service activities.

Exploration & Production Activities

Including the acquisition of properties from Devon, as of May 31, 2004, the Company controlled approximately 548,000 net acres. The petroleum engineering firm of Cawley, Gillespie & Associates, Inc., of Ft. Worth, Texas, estimated the Company's proved oil and natural gas reserves to be as follows as of May 31, 2004: estimated gross natural gas proved reserves of 212.5 Bcf, of which 133.6 Bcf is net to the Company, and estimated net proved oil reserves of 57,105 barrels. The present value of these reserve assets, discounted at 10% of the future net cash flow from the net natural gas and oil reserves, is $318.4 million.

As of May 31, 2004, the Company was producing natural gas from approximately 678 wells (gross) at an average per well rate of 48 mcf/d measured at the wellhead. The Company's total daily natural gas sales (including pipeline-earned volume) as of May 31, 2004 were approximately 24,500 mcf/d net (32,600 mcf/d gross).

The Company has a significant amount of acreage available for development. As of May 31, 2004, the Company had leases with respect to 333,993 net undeveloped acres. For the last five months of the 2003 fiscal year, the Company was drilling wells at an annualized rate of approximately 325 wells per year. During the 2005 fiscal year, the Company intends to drill approximately 380 wells and intends to drill approximately 1,140 wells over the next three years. The Company has identified over 600 proved undeveloped drilling locations and many more probable and possible drilling locations. The Company believes that it has the necessary expertise, manpower, equipment and funding capabilities required to carry out these development plans. Management believes that significant additional value will be created for the Company if the drilling program continues to be successful in creating new natural gas wells that convert raw acreage into proven natural gas reserves. However, there can be no assurance that the Company will be able to drill and develop that number of wells during such time frame or as to the number of new wells that will be producing wells.

Most of this development type of drilling is in areas of known natural gas reserves that involve much lower risk than the exploratory type of drilling that is required when searching for new natural gas reserves. The Company has enjoyed a new well success rate of over 90% and the typical new well has been adding value to the Company amounting to several times the Company's approximate $60,000 historical cost for drilling and completing a well in the Cherokee Basin. This development work is being conducted by Company personnel, who have over 100 years of combined experience in coalbed methane development in the Cherokee Basin.

Producing Wells and Acreage. The following table sets forth certain information regarding the ownership by the Company of productive wells and total acreage, as of May 31, 2004, 2003 and 2002. For purposes of this table, productive wells are: wells currently in production, wells capable of production, and new wells in the process of completion.

Year	PRODUCTIVE WELLS						LEASEHOLD ACREAGE					
Ended	Natural Gas		Oil		Total		Developed		Undeveloped		Total Leased	
May 31	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2002	84	73.6	43	41.6	127	115.2	4,847	4,362	72,399	65,159	77,246	69,521
2003	227	213.8	31	29.9	258	243.7	37,088	35,954	78,716	76,748	115,804	112,702
2004	678	660.4	29	27.9	707	688.3	229,080	214,145	436,079	333,993	665,159	548,138

During the 2004 fiscal year, the Company drilled 175 gross (170 net) new wells on its properties all of which were natural gas wells. Of the 175 gross wells drilled, 138 gross wells had been evaluated and were included in the year end reserve report. Only two additional wells were drilled and deemed to be dry holes that were not worthy of completion. The oil well count continues to decline as the Company focus on adding natural gas reserves. ("See Summary of New and Abandoned Well Activity"). In addition to the Devon acquisition, the Company has continued an active land leasing program during the 2004 fiscal year that has contributed to the increase in Total Leased Acreage in the above table.

Natural gas and oil reserves. The following table summarizes the reserve estimate and analysis of net proved reserves of natural gas and oil as of May 31, 2004, 2003 and 2002, in accordance with SEC guidelines. The May 31, 2004 and 2003 data was prepared by the petroleum engineering firm Cawley, Gillespie & Associates, Inc. in Ft. Worth, Texas. The petroleum engineering firm McCune Engineering prepared the reserve estimates for the fiscal year ending May 31, 2002. The present value of estimated future net revenues from these reserves was calculated on a non-escalated price basis discounted at 10% per year. The Devon property acquisition during fiscal year 2004 more than tripled the estimated proved reserves over previous years. The acquisition of natural gas reserves from the Perkins/Willhite acquisition, effective June 1, 2003 is estimated to have increased the Company's reserves shown below for fiscal year 2003 by approximately 13%. Although we do have proved undeveloped oil reserves, they are insignificant, so no effort was made to calculate such reserves for 2004 and 2003. The Company's estimated proved reserves have not been filed with or included in reports to any federal agency, except the Securities and Exchange Commission, during the fiscal years ended May 31, 2004, 2003 and 2002.

	May 31,		
	2004	2003	2002
Proved Developed Gas Reserves (mcf)	62,558,900	14,016,064	6,356,220
Proved Undeveloped Gas Reserves (mcf)	71,017,300	14,254,570	8,513,750
Total Proved Gas Reserves (mcf)	133,576,200	28,270,634	14,869,970
Proved Developed Oil Reserves (bbl)	57,105	43,083	45,944
Proved Undeveloped Oil Reserves (bbl)	-	-	177,262
Total Proved Oil Reserves (bbl)	57,105	43,083	223,206
Future Net Cash Flow (after operating expenses)	$ 482,745,600	$ 95,572,500	$ 25,854,629
Present Value of Future Net Cash Flow	$ 318,356,000	$ 69,954,990	$ 17,367,534

There are numerous uncertainties inherent in estimating natural gas and oil reserves and their values. The reserve data set forth in this report is only an estimate. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Furthermore, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing natural gas and oil prices, operating costs and other factors, and such revisions can be substantial. Accordingly, reserve estimates often differ from the quantities of natural gas and oil that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based.

The proved reserves of the Company will generally decline as they are produced, except to the extent that the Company conducts revitalization activities, or acquires properties containing proved reserves, or both. To increase reserves and production, the Company intends to continue its development drilling and re-completion programs, to identify and produce previously overlooked or bypassed zones in shut-in wells, and to acquire additional properties or undertake other replacement activities. The Company's current strategy is to increase its reserve base, production and cash flow through the development of its existing natural gas fields and through the selective acquisition of other promising properties where the Company can utilize its existing technology and infrastructure. The Company can give no assurance that its planned development activities will result in significant additional reserves or that the Company will have success in discovering and producing reserves at economical exploration and development costs. The drilling of new wells and conversion of existing oil wells for natural gas production is a speculative activity and the possibility always exists that newly drilled or converted natural gas wells will be non-productive or fail to produce enough revenue to be commercially worthwhile.

Production volumes, sales prices, and production costs. The following tables set forth certain information regarding the natural gas and oil properties owned by the Company through its subsidiaries. The natural gas and oil production figures reflect the net production attributable to the Company's revenue interest and are not indicative of the total volumes produced by the wells.

The significant increase in net natural gas production shown in the table below demonstrates the success of our natural gas development program and the Devon property acquisition during fiscal year 2004 and the acquisition of STP during fiscal year 2003. The decline in oil production reflects the Company's focus on developing its natural gas reserves.

Gas Production Statistics	Years Ended May 31,		
	2004	2003	2002
Net gas production (mcf)	5,530,208	1,488,679	508,077
Average wellhead gas price (per mcf)	$5.03	$5.42	$1.62
Average production cost (per mcf)	$1.24	$1.29	$0.57
Net revenue (per mcf)	$3.79	$4.13	$1.05

The 2004 fiscal year natural gas production volume includes the Devon acquisition beginning December 22, 2003 and the Perkins/Willhite acquisition beginning June 1, 2003 and the 2003 fiscal year natural gas production volume includes STP production beginning November 1, 2002.

Oil Production Statistics	Years Ended May 31,		
	2004	2003	2002
Net oil production (bbls)	8,549	14,123	11,954
Average wellhead oil price (per bbl)	$37.94	$19.91	$19.12
Average production cost (per bbl)	$16.89	$16.74	$20.02
Net revenue (per bbl)	$21.05	$3.17	$(0.90)

Summary of New and Abandoned Well Activity. Most of the wells expected to be drilled in the next year will be of the development category and in the vicinity of the Company's pipeline network. However, the Company will continue to devote a small part of its drilling effort into exploratory wells in an attempt to discover new natural gas reserves, which is a high risk endeavor. The Company's drilling, re-completion, abandonment, and acquisition activities for the periods indicated are shown below:

	Years ended May 31,									
	2004				2003				2002	
	Oil		Gas		Oil		Gas		Oil and Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells Drilled										
Capable of Production	-	-	-	-	-	-	-	-	-	-
Dry	-	-	-	-	-	-	-	-	4	4
Development Wells Drilled										
Capable of Production	-	-	138	132	1	1	45	45	33	25
Dry	-	-	2	2	-	-	1	1	2	2
Re-completion of Old Wells										
Capable of Production	-	-	-	-	-	-	-	-	4	1
Dry	-	-	-	-	-	-	-	-	-	-
Wells Abandoned	2	2	-	-	(13)	(13)	(21)	(18)	(1)	(1)
Acquired Devon wells 12/22/03	-	-	337	337	-	-	-	-	-	-
Acquired STP11/1/02	-	-	-	-	-	-	108	105	-	-
Other Wells Acquired	-	-	-	-	-	-	9	8	-	-
Net increase in Capable Wells	(2)	(2)	477	471	(12)	(12)	143	140	36	28

The Company's coalbed methane gas wells are the most productive and profitable category of wells in its inventory. The Company's older natural gas wells and oil wells are 10 to 20 years old and are much less profitable than its typical coalbed methane well. By abandoning the marginal or non-commercial wells, the Company is more focused on its more profitable coalbed methane wells. The 175 new natural gas wells drilled (138 included in year end reserve report) in the 2004 fiscal year are not indicative of the current level of drilling activity because it was a partial year for the Devon acquisition. Subsequent to the Devon acquisition, the Company has drilled a monthly average of 27 wells for the five months ended May 31, 2004 and the Company expects to increase this monthly average to 32 for the next fiscal year.

Subsequent to May 31, 2004, the Company's aggressive new well development program is well underway. The Company drilled 47 wells during June 2004, 36 during July 2004 and 43 during August of 2004. As of September 17, 2004 the Company was in the process of drilling 5 wells and 38 wells were in the process of being completed.

Delivery Commitments

Natural Gas. The Company does not have long-term delivery commitments. The Company markets it own natural gas and more than 90% of the natural gas is sold to ONEOK Energy Marketing and Trading Company. No other customer of the Company accounted for more than 10% of the consolidated revenues for fiscal years 2004, 2003 or 2002.

Oil. The Company's oil has been sold to Plains Marketing, L.P. for the past several years. The oil is collected at the various tank batteries on the producing properties and delivered to the Plains Marketing terminal for a transportation fee. The Company does not have a long term contract with Plains Marketing.

Hedging Activities. The Company seeks to reduce its exposure to unfavorable changes in natural gas prices, which are subject to significant and often volatile fluctuation, through the use of fixed-price contracts. The fixed-price contracts are comprised of energy swaps and collars. These contracts allow the Company to predict with greater certainty the effective natural gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. Collar structures provide for participation in price increases and decreases to the extent of the ceiling prices and floors provided in those contracts.

The following table summarizes the estimated volumes, fixed prices, fixed-price sales and fair value attributable to the fixed-price contracts as of May 31, 2004. See Note 17 of the Notes to Consolidated Financial Statements appearing elsewhere in this document.

	Years Ending May 31,			
	2005	**2006**	**2007**	**Total**
	(dollars in thousands, except price data)			
Natural Gas Swaps:				
Contract vols (MMBtu)	5,741,000	5,633,000	3,292,000	14,666,000
Weighted-avg fixed price per MMBtu (1)	$ 4.96	$ 4.62	$ 4.53	$ 4.73
Fixed-price sales	$ 28,468	$ 26,030	$ 14,912	$ 69,410
Fair value liability (2)	$ (8,779)	$ (7,010)	$ (2,355)	$ (18,144)
Natural Gas Collars:				
Contract vols (MMBtu):				
Floor	1,307,000	612,000	--	1,919,000
Ceiling	1,307,000	612,000	--	1,919,000
Weighted-avg fixed price per MMBtu (1):				
Floor	$ 4.22	$ 4.25	$ --	$ 4.23
Ceiling	$ 5.38	$ 5.30	$ --	$ 5.36
Fixed-price sales (3)	$ 7,034	$ 3,244	$ --	$ 10,278
Fair value liability (2)	$ (1,308)	$ (336)	$ --	$ (1,644)
Total Natural Gas Contracts:				
Contract vols (MMBtu)	7,048,000	6,245,000	3,292,000	16,585,000
Weighted-avg fixed price per MMBtu (1)	$ 5.04	$ 4.69	$ 4.53	$ 4.80
Fixed-price sales (3)	$ 35,502	$ 29,274	$ 14,912	$ 79,688
Fair value liability (2)	$ (10,087)	$ (7,346)	$ (2,355)	$ (19,788)

(1) The prices to be realized for hedged production are expected to vary from the prices shown due to basis. See Note 17 of the Notes to Consolidated Financial Statements.

(2) Bracketed amounts are reflected as derivative liabilities on the balance sheet. See Note 16 of the Notes to Consolidated Financial Instruments.

(3) Assumes ceiling prices for natural gas collar volumes.

The estimates of fair value of the fixed-price contracts are computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date, as adjusted for basis. Forward market prices for natural gas are dependent upon supply and demand factors in such forward market and are subject to significant volatility. The fair value estimates shown above are subject to change as forward market prices and basis change. See Note 16 of the Notes to Consolidated Financial Instruments.

Pipeline Operations

The Company owns and operates an approximate 900 mile natural gas gathering pipeline network located throughout ten counties in southeastern Kansas and northeastern Oklahoma. This pipeline network provides a market outlet for natural gas in a region of approximately 1,000 square miles in size and has connections to both intrastate and interstate delivery pipelines. Included in this pipeline network are 16 natural gas compressors which are owned by the Company and 40 larger compressors that are rented.

The pipelines gather all of the natural gas produced by the Company in addition to some natural gas produced by other companies. The pipeline network is a critical asset for the Company's future growth because natural gas gathering pipelines are a costly component of the infrastructure required for natural gas production and such pipelines are not easily constructed. Much of the undeveloped acreage targeted by the Company for future development is readily accessible to the Company's existing pipeline network, which management believes is a significant advantage.

The Company is continuing to expand its pipeline infrastructure through a combination of the development of new pipelines and the acquisition of existing pipelines. During fiscal year 2004, the Company acquired approximately 475 miles of natural gas gathering pipelines through the Devon property acquisition and the Perkins/Willhite acquisition. These acquired pipeline systems are located near the Company's current network of pipeline systems.

The Company's pipeline operations are conducted through Bluestem Pipeline LLC.

The table below sets forth the natural gas volumes transported by the Company on its pipeline network during each of the last three fiscal years.

	Years Ended May 31,		
	2004	2003	2002
Pipeline Network Natural Gas Volumes (mcf)	8,157,000	2,699,000	1,415,000

The natural gas volume for the fiscal year 2004 includes the Devon acquisition beginning December 22, 2003 and the Perkins/Willhite acquisition beginning June 1, 2003. The natural gas volume for fiscal year 2003 includes STP volumes beginning November 1, 2002. As of May 31, 2004, the total daily capacity is approximately 57 mmcf and the total utilization is approximately 34 mmcf or 60%.

Service Operations

The Company has an experienced staff of 121 field employees in offices located in Benedict and Howard, Kansas and Lenapah, Oklahoma. The headquarters office in Oklahoma City is staffed with 18 executive and administrative personnel. The Company's management and key personnel have been involved in oil and natural gas production activities in the Cherokee Basin for more than 100 years.

Field operations conducted by Company personnel include duties performed by "pumpers" or employees whose primary responsibility is to operate the wells and the pipelines. Other field personnel are experienced and involved in the activities of well servicing, pipeline maintenance, the development and completion of new wells and associated infrastructure, new pipeline construction and the construction of supporting infrastructure for new wells (such as electric service, salt water disposal facilities, and natural gas feeder lines). The primary equipment categories owned by the Company are trucks, well service rigs and construction equipment. The Company also owns a repair and fabrication shop that is located in Benedict, Kansas.

By retaining operational control of the Company's crucial income producing assets, management believes that the Company is better able to control costs and minimize downtime of these critical assets.

The Company does not currently provide a material amount of services to unaffiliated companies.

Regulation

The Company's business is affected by numerous federal, state and local laws and regulations, including, among others, laws and regulations relating to energy, environment, conservation and tax.

Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used and produced in connection with operations.

The Company's operations are also subject to various conservation laws and regulations. These include: (1) pro-ration units; (2) the density of wells that may be drilled; and (3) the unitization or pooling of natural gas and oil properties. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, which generally limit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation.

The Company's cost of maintaining environmental compliance is less than $10,000 per year.

The Company is also subject to extensive federal, state and local environmental laws and regulations that, among other things, regulate the discharge or disposal of materials or substances into the environment and otherwise are intended to protect the environment. Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial administrative, civil and/or criminal penalties and, in some cases, injunctive relief for failure to comply. Some laws, rules and regulations relating to the protection of the environment may, in certain circumstances, impose "strict liability" for environmental contamination. Such laws render a person or company liable for environmental and natural resource damages, cleanup costs and, in the case of oil spills in certain states, consequential damages without regard to negligence or fault. Other laws, rules and regulations may require the rate of natural gas and oil production to be below the economically optimal rate or may even prohibit exploration or production activities in environmentally sensitive areas. In addition, state laws often require some form of remedial action such as closure of inactive pits and plugging of abandoned wells to prevent pollution from former or suspended operations. Legislation has been proposed and continues to be evaluated in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes." This reclassification would make such wastes subject to much more stringent and expensive storage, treatment, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant adverse impact on the operating costs of the Company, as well as the natural gas and oil industry in general. Initiatives to regulate further the disposal of natural gas and oil wastes are also proposed in certain states from time to time and may include initiatives at county, municipal and local government levels. These various initiatives could have a similar adverse impact on the Company.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of injunctive relief or both. Moreover, changes in any of these laws and regulations could have a material adverse effect on the Company's business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to the Company, the Company cannot predict the overall effect of such laws and regulations on its future operations.

The Company believes that its operations comply in all material respects with applicable laws and regulations and that the existence and enforcement of such laws and regulations have no more restrictive effect on the Company's method of operations than on other similar companies in the energy industry. Internal procedures and policies exist within the Company to ensure that its operations are conducted in substantial regulatory compliance.

Competition

The Company operates in the highly competitive areas of acquisition and exploration of natural gas properties in which other competing companies may have substantially larger financial resources, operations, staffs and facilities. In seeking to acquire desirable new properties for future exploration the Company faces competition from other natural gas and oil companies. Such companies may be able to pay more for prospective natural gas properties or prospects and to evaluate, bid for and purchase a greater number of properties and prospects than the Company's financial or human resources permit.

Since a significant majority of the Company's pipeline and service operations presently support the Company's exploration and development operations, these aspects of the Company's business do not experience any significant competition.

Employees

As of September 17, 2004, the Company had 161 employees. None of our employees are covered by a collective bargaining agreement. The Company considers its relations with its employees to be satisfactory.

Administrative Facilities.

The corporate headquarters for the Company and its subsidiaries is located in Suite 300 at 9520 N. May Avenue in Oklahoma City, OK 73120. Prior to July 2004, the offices were located at Suite 200 at 5901 N. Western in Oklahoma City, Oklahoma 73118 and the space was rented from Mr. Cash, who is the Chairman, Co-Chief Executive Officer and a director of the Company for the amount of $3,050 monthly.

An administrative office for the Company and its subsidiaries is located at 701 East Main Street in Benedict, Kansas 66714. It is leased from Crown Properties, LC for $400 per month. Crown Properties, LC is owned by Marsha K. Lamb who is the wife of Mr. Lamb, the Co-Chief Executive Officer, President, and a director of the Company.

An office building at 127 West Main in Chanute, Kansas is owned and operated by the Company as a geological laboratory.

Where To Find Additional Information

Additional information about the Company can be found on our website at www.qrcp.net. We also provide on our website the Company's filings with the SEC, including our annual reports, quarterly reports, and current reports along with any amendments thereto, as soon as reasonably practicable after the Company has electronically filed such material with the SEC.

Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Form 10-KSB.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of gas equivalent.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry Hole; Dry Well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Exploratory Well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Full Cost Pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which a working interest is owned.

Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

Mbtu. One thousand btus.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of gas equivalent.

Mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of gas equivalent.

Net Acres or Net Wells. The sum of the fractional working interest owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

ITEM 3. LEGAL PROCEEDINGS

The Company and STP have been named Defendants in a lawsuit (Case #CJ-2003-30) filed by Plaintiffs Eddie R. Hill et al on March 27, 2003 in the District Court for Craig County, Oklahoma. Plaintiffs are royalty owners who are alleging underpayment of royalties owed them by STP and the Company. The plaintiffs also allege, among other things, that STP and the Company have engaged in self-dealing, have breached their fiduciary duties to the plaintiffs and have acted fraudulently towards the plaintiffs. The plaintiffs are seeking unspecified actual and punitive damages as a result of the alleged conduct by STP and the Company. Based on the information available to date and our preliminary investigation, we believe that the claims against us are without merit and intend to defend against them vigorously.

STP has been named as Defendant in a lawsuit (Case #CJ-2003-137) filed by Plaintiff Davis Operating Company on October 14, 2003 in the District Court of Craig County, Oklahoma. Plaintiff is alleging improper operation of a natural gas gathering system. The plaintiff is seeking unspecified actual and punitive damages as a result of the alleged improper operations by STP. Discovery is ongoing and the case is scheduled for trial in September 2004. Based on the information available to date and a preliminary investigation, the Company believes that the claims are without merit and intends to defend against them vigorously.

The Company, from time to time, may be subject to legal proceedings and claims that arise in the ordinary course of its business. Although no assurance can be given, management believes, based on its experiences to date, that the ultimate resolution of such items will not have a material adverse impact on the Company's business, financial position or results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of the stockholders of the Company during the fourth quarter of the fiscal year ended May 31, 2004.

PART II

ITEM 5. MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

The Company's common stock was approved for trading on the OTC Bulletin Board on June 8, 1999, under the symbol "QRCP." On February 23, 2004, the Company's stock ceased trading on the OTC Bulletin Board due to the failure of the Company to timely file its Form 10-QSB for the quarter ended November 30, 2003. The delay in the filing was due in part to the Company's need to restate its financial statements as discussed elsewhere in this report. The Company has completed the restatement of its financial statements and has resumed filing reports with the SEC. The Company is currently actively seeking to get its common stock approved for trading on the OTC Bulletin Board.

The table set forth below lists the range of high and low bids of the Company's common stock for each quarter of the Company's last two fiscal years. The prices in the table reflect inter-dealer prices, without retail markup, markdown or commission and may not represent actual transactions.

	Fiscal Quarter Ended	
	High Price	Low Price
May 31, 2004	$ 4.30	$ 3.20
February 29, 2004	$ 4.60	$ 2.80
November 30, 2003	$ 4.60	$ 3.20
August 31, 2003	$ 3.71	$ 2.85
May 31, 2003	$ 4.00	$ 2.40
February 28, 2003	$ 3.85	$ 1.95
November 30, 2002	$ 2.70	$ 1.28
August 31, 2002	$ 1.72	$ 1.22

The source for the information contained in the table above is Investools @ www.investortoolbox.com. The closing price for QRCP stock on September 16, 2004 was $4.40.

Record Holders

Common Stock. There are 950,000,000 shares of common stock authorized for issuance. As of September 16, 2004, there were 14,112,694 shares of common stock issued and outstanding, held of record by approximately 2,140 shareholders.

Preferred Stock. There are 50,000,000 shares of preferred stock authorized for issuance. 500,000 shares of the authorized preferred stock have been classed as Series A Convertible Preferred Stock. Holders of Series A Convertible Preferred Stock are entitled to cumulative quarterly dividends at the annual rate of 10% on the purchase price of $10.00 per share and to convert each share into four shares of common stock. As of September 16, 2004, 10,000 shares of Series A Convertible Preferred Stock were issued and outstanding and held by two shareholders.

Dividends

The payment of dividends on the Company's stock is within the discretion of the board of directors and will depend on the Company's earnings, capital requirements, financial condition and other relevant factors. The Company has not declared any cash dividends on its common stock for the last two fiscal years and does not anticipate paying any dividends on its common stock in the foreseeable future. Dividends are being paid at the rate of 10% on the Series A Convertible Preferred Stock in accordance with the Series A Convertible Preferred Stock terms and conditions. Management intends to continue paying dividends on the preferred stock for the foreseeable future.

Although there are currently no contractual restrictions on the ability of the Company to pay dividends on its common stock, for the foreseeable future the primary source of any funds that would be used to pay dividends will be distributions from Quest Cherokee to the Company. The ability of Quest Cherokee to make distributions to the Company is subject to restrictions contained in its limited liability company agreement, the subordinated promissory note issued to ArcLight and in its credit facilities. See Item 6. "Management's Discussion and Analysis or Plan of Operation—Capital Resources and Liquidity" for a discussion of these restrictions.

Securities Authorized for Issuance under Equity Compensation Plans

None

Recent Sales of Unregistered Securities

None

Purchases of Equity Securities

None

ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OR PLAN OF OPERATION

As disclosed in the Company's Form 10-KSB/A (Amendment No. 2) for 2003 filed with the SEC on September 10, 2004, the Company has restated its financial statements for the fiscal years ended May 31, 2003 and 2002, and for the fiscal quarters ended August 31, 2002, November 30, 2002, February 28, 2003 and August 31, 2003. The Company determined that the restatements were necessary after an internal review of financial statements and supporting documentation determined that certain transactions were recorded incorrectly. In addition, the Company either failed to adopt or improperly adopted various accounting pronouncements for the fiscal year ended May 31, 2003. See Note 2 to the Consolidated Financial Statements included in this report.

The following discussion of financial condition and results of operations should be read in conjunction with the restated consolidated financial statements and the notes to the restated consolidated financial statements, which are included elsewhere in this report.

Cautionary Statements For Purpose Of The "Safe Harbor" Provisions Of The Private Securities Litigation Reform Act of 1995

The following discussion and analysis should be read in conjunction with the financial statements and notes thereto appearing elsewhere herein. Some of the information in this report and in the Company's press releases and other filings with the SEC contain forward-looking statements within the meaning set forth in Section 21E of the Securities Exchange Act of 1934. Forward-looking statements generally can be identified by the use of forward looking terminology such as "may," "will," "expect," "intend," "project," "estimate," "anticipate," "believe" or "continue" or the negative thereof or similar terminology. These statements express, or are based on, the Company's expectations about future events. These include such matters as:

- financial position;
- business strategy;

- budgets;
- amount, nature and timing of capital expenditures;
- drilling of wells;
- acquisition and development of natural gas and oil properties;
- timing and amount of future production of natural gas and oil;
- operating costs and other expenses;
- estimated future net revenues from natural gas and oil reserves and the present value thereof;
- cash flow and anticipated liquidity; and
- other plans and objectives for future operations.

Although the Company believes that the expectations reflected in these forward looking statements are reasonable, there can be no assurance that the actual results or developments anticipated by the Company will be realized or, even if substantially realized, that they will have the expected effects on its business or operations. There are many factors that could cause these forward-looking statements to be incorrect, including, but not limited to, the risks described in Exhibit 99.1 "Risk Factors" to this report, which are incorporated herein by reference. These factors include, among others:

- the ability of the Company to implement its business strategy;
- the extent of the Company's success in discovering, developing and producing reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;
- fluctuations in the commodity prices for natural gas and crude oil;
- engineering and mechanical or technological difficulties with operational equipment, in well completions and workovers, and in drilling new wells;
- land issues;
- federal and state regulatory developments;
- labor problems;
- environmental related problems;
- the uncertainty inherent in estimating future natural gas and oil production or reserves;
- production variances from expectations;
- the substantial capital expenditures required for construction of pipelines and the drilling of wells and the related need to fund such capital requirements through commercial banks and/or public securities markets;
- the need to develop and replace reserves;
- competition;
- dependence upon key personnel;
- the lack of liquidity of the Company's equity securities;
- operating hazards attendant to the natural gas and oil business;
- down-hole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells;
- climatic conditions;
- availability and cost of material and equipment;
- delays in anticipated start-up dates;
- the Company's ability to find and retain skilled personnel;
- availability of capital;
- the strength and financial resources of the Company's competitors; and
- general economic conditions.

When you consider these forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this report or incorporated by reference. The Company's forward-looking statements speak only as of the date made. All subsequent oral and written forward looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these factors. The Company assumes no obligation to update any of these statements.

Overview of Company Status

The successful integration of the three major acquisitions that have occurred during the last two fiscal years (Devon, Perkins/Willhite and STP) into one new organization has allowed us to support new levels of development and operational activities for record-setting growth this year. This integration has been accomplished with all of the Company's personnel now comprising an effective new team.

Our strategic positioning in the southeastern Kansas and northeastern Oklahoma natural gas industry has yielded significant increases in total revenues and has resulted in a solid foundation for future growth. The Company enjoyed a significant improvement in profitability in fiscal year 2004 as a result of increased natural gas prices over the levels realized in fiscal 2003. However, most of the increase in total revenues for the 2004 fiscal year is primarily due to the Devon property acquisition and the Perkins/Willhite acquisition that occurred during the year, a full year of operations from the STP acquisition that was completed in November 2002. Operating results were also favorably affected by the increased level of new well development that was achieved during the year as a result of the increased funding of the Company's drilling program using the credit facilities from Bank One Texas, N.A. See Items 1 and 2. "Description of Business and Properties."

By the end of the 2004 fiscal year, Quest had an interest in 678 natural gas and oil wells (gross) and natural gas and oil leases on approximately 665,000 gross acres. Management believes that the proximity of the 900 mile Company-owned pipeline network to these natural gas and oil leases will enable the Company to quickly develop new producing wells on many of its un-drilled properties. The current inventory of undeveloped acreage is expected to yield more than 600 additional natural gas well drilling sites. With approximately 380 new wells planned for each of the next several years, the Company is positioned for significant growth in natural gas production, revenues, and net income. However, no assurance can be given that the Company will be able to achieve its anticipated rate of growth.

Results of Operations

The following information presents the operations of the Company and its subsidiaries on a consolidated basis and should be read in conjunction with the consolidated financial statements and accompanying notes contained elsewhere in this report.

Total revenues of $30,011,000 for the year ended May 31, 2004 represents an increase of 271% when compared to total revenues of $8,098,000 for the fiscal year ended May 31, 2003. This increase was achieved by a combination of the additional producing wells from the Devon acquisition in December 2003, the Perkins/Willhite acquisition in June 2003, the STP acquisition in November 2002 and the Company's aggressive new well development program.

The increase in natural gas and oil sales from $8,345,000 in fiscal year 2003 to $28,147,000 in fiscal year 2004 and the increase in natural gas pipeline revenue from $632,000 to $2,707,000 resulted from the Devon, STP and the Perkins/Willhite acquisitions and the additional wells and pipelines acquired or completed during the past twelve months. The Devon, STP and Perkins/Willhite acquisitions and the additional wells acquired or completed contributed to the production of 5,530,208 mcf of net gas in fiscal year 2004, as compared to 1,488,679 net mcf produced in the prior fiscal year. The Company's product prices on an equivalent basis (mcfe) decreased from $5.30 mcfe average for 2003 to $5.04 average for 2004. Since new well development is an ongoing program, management expects most of the above revenue categories to continue growing in the foreseeable future. In order to reduce natural gas price volatility, the Company has established a program to hedge natural gas prices. As of June 1, 2004, the Company had entered into hedging transactions covering a total of approximately 16.6 Bcf of natural gas production through December 2006. Subsequent to year end, in connection with the establishment of new credit facilities with UBS, the Company entered into additional hedging transactions covering approximately 10.2 Bcf of natural gas production through December 2008. See Items 1 and 2 "Description of Business and Properties—Company Operations—Exploration & Production Activities–Hedging Activities" and Note 17 to the Consolidated Financial Statements included in this report.

Other expense for the fiscal year ended May 31, 2004 was $843,000 as compared to other expense of $879,000 for the fiscal year ended May 31, 2003, resulting from recording the loss on hedge settlements for the two comparative periods.

The operating costs for fiscal year ended May 31, 2004 totaled approximately $6.8 million as compared to operating costs of approximately $1.9 million incurred for fiscal year ended May 31, 2003. Operating costs per mcf for fiscal year May 31, 2004 were $1.24 per mcf as compared to $1.29 per mcf for fiscal year ended May 31, 2003, representing a 4% decrease. Pipeline operating costs for fiscal year ended May 31, 2004 totaled approximately $3.5 million as compared to pipeline operating costs of $912,000 incurred for fiscal year ended May 31, 2003. The increase in operating costs are due to the Devon, STP and Perkins/Willhite acquisitions and the number of wells acquired, completed and operated during the year and the increased miles of pipeline in service. The increase in depreciation, depletion and amortization to approximately $7.7 million from approximately $1.8 million is a result of the increased number of producing wells and miles of pipelines acquired and developed, the higher volumes of natural gas and oil produced and the higher cost of properties recorded by application of the purchase method of accounting to record the Devon acquisition, the STP acquisition and the Perkins/Willhite acquisition.

General and administrative expenses increased to approximately $2.6 million in fiscal year 2004 from $977,000 in the prior year due primarily to the Devon, STP and Perkins/Willhite acquisitions, the increased staffing to support the higher levels of development and operational activity and the added resources to enhance the Company's internal controls and financial reporting. See Item 8A. "Controls and Procedures"

Interest expense increased to approximately $8.1 million for fiscal year 2004 from $727,000 for fiscal year 2003, due to the increase in the Company's outstanding borrowings related to the Devon, STP and Perkins/Willhite acquisitions and equipment, development and leasehold expenditures and the expense of $1.0 million related to the retirement of the Wells Fargo credit facilities.

Change in derivative fair value was a non-cash net loss of $2.0 million for the fiscal year ended May 31, 2004, which included a $1.7 million net loss attributable to the change in fair value for certain cash flow hedges which did not meet the effectiveness guidelines of SFAS 133 for the fiscal year, a $888,000 net gain attributable to the reversal of contract fair value gains and losses recognized in earnings prior to actual settlement, and a loss of $1.2 million relating to hedge ineffectiveness. Change in derivative fair value was a non-cash net loss of $4.9 million for the year ended May 31, 2003, which was attributable to the change in fair value of cash flow hedges which did not meet the effectiveness guidelines of SFAS 133 for the year. Amounts recorded in this caption represent non-cash gains and losses created by valuation changes in derivatives which are not entitled to receive hedge accounting. All amounts recorded in this caption are ultimately reversed in this caption over the respective contract term.

The Company generated income of $1.4 million before income taxes and before the change in derivative fair value of $2.0 million for fiscal year 2004, compared to income of approximately $1.7 million before income taxes and before the change in derivative fair value of $4.9 million in the previous fiscal year.

The income tax benefit for the fiscal year ended May 31, 2004 was $245,000 compared to the income tax expense of $374,000 for the fiscal year ended May 31, 2003, inclusive of a tax benefit of approximately $620,000 and the resulting limitation of net operating loss carry forwards, both resulting from the STP acquisition.

The Company recorded a net loss of $393,000 for fiscal year 2004 as compared to a net loss of approximately $3.6 million for fiscal year 2003.

Capital Resources and Liquidity

At May 31, 2004, the Company had current assets of $12.2 million, working capital (current assets minus current liabilities, excluding the short-term derivative liability of $10.1 million) of $4.4 million and had generated $11.8 million net cash from operations during the fiscal year ended May 31, 2004.

During the fiscal year ended May 31, 2004, including the Devon acquisition and the Perkins/Willhite acquisition, a total of approximately $146.4 million was invested in new natural gas wells and properties, new pipeline facilities, and other additional capital items. This investment was substantially funded by operational cash flow and by an increase of approximately $142.9 million in long-term debt.

Net cash provided from operating activities increased substantially from $4.0 million for the fiscal year ended May 31, 2003 to $11.8 million for the fiscal year ended May 31, 2004 due primarily to the expanded operations of the Company as discussed above.

The Company's working capital (current assets minus current liabilities, excluding the short-term derivative liability of $10.1 million) was $4.4 million at May 31, 2004, compared to $2.4 million, excluding the short-term derivative liability of $3.8 million, at May 31, 2003. The increase results from the expanded operations due to the completion of the Devon, STP, and Perkins/Willhite acquisitions. Additionally, accounts receivable, inventory, accounts payable, oil and gas payable and accrued expenses balances increased as the Company continues to expand its operations. There is a substantial increase in both receivables and payables on the balance sheet for May 31, 2004 as compared to May 31, 2003. This increase is largely due to the substantial increase in operating activity being conducted by the Company.

The Company intends to continue acquiring property and developing additional wells using the resources generated by its operations and its financing facilities, and to seek additional sources of funding to allow acceleration of development activity to the desired rate of approximately 380 wells per year, which will require a capital investment of approximately $28 million per year to drill and develop. Management anticipates funding a significant portion of the higher rate of new well development with internally generated cash flow and bank financing through the new credit facilities with UBS. See - "UBS Credit Facility". However, no assurances are given that such sources will be sufficient to fund the Company's anticipated level of new well development. In the event that additional financing is required, the Company could seek to borrow additional funds or sell equity securities. However, no assurances are given that the Company would be able to obtain such financing on terms favorable to Quest, if at all.

The Company anticipates that it will require less than $1.0 million over the next 12 months to conduct its technical study of the property in western Kentucky leased from Alcoa Fuels. At the end of the first year, the Company obtained a five month extension on its deadline for extending the lease for an additional four years, which extension would require a payment of an agreed upon amount. In the event that the Company determines that it is feasible to develop the property and elects to extend the lease, developing this property could require the Company to obtain significant additional capital resources. The Company currently estimates that the gross costs to drill and complete a well on this property, is approximately $180,000 and the Company's current working interest is approximately 50%. Since this property is outside of Quest Cherokee, the assets and financial resources of Quest Cherokee will not be available to support the development of this property. There can be no assurance that the Company will be able to obtain the necessary financing to develop the Kentucky property or that the terms of any financing that it does obtain will be on terms favorable to the Company.

Subsequent to year end, the Company acquired approximately 80 miles of an inactive oil pipeline for approximately $1.0 million. The Company intends to convert this former oil pipeline into a natural gas pipeline. Additionally, the Company acquired certain assets from Consolidated Oil Well Services on September 15, 2004 in the amount of $4.1 million. The assets consist of cementing, acidizing and fracturing equipment and a related office building and storage facility in Chanute, Kansas. Both of these acquisitions were funded with a portion of the remaining net proceeds from the $120 million term loan under the new credit facility with UBS in July 2004. See "—UBS Credit Facility

Although the Company believes that it will have adequate additional reserves and other resources to support the expanded development plans, no assurance can be given that the Company will be able to obtain funding sufficient to support all of its' development plans.

Bank One Credit Faciltiies

In connection with the December 22, 2004 Devon asset acquisition, the previous credit facilities with Wells Fargo Bank Texas, N.A. and Wells Fargo Energy Capital, Inc. were paid off. The Company, through its subsidiary Quest Cherokee, entered into a Credit Agreement consisting of a three year $200.0 million senior revolving loan (the "Revolving Credit Agreement") and a five year $35.0 million senior term second lien secured loan (the "Term Loan Agreement") arranged and syndicated by Banc One Capital Markets, Inc. and with Bank One, NA, as agent.

The Revolving Credit Agreement provided for an initial borrowing base of $57.0 million, which amount was increased to $70.0 million upon delivery to the administrative agent of a certificate evidencing that third party consents had been obtained for the assignment of certain natural gas and oil leases from Devon. The borrowing base is scheduled to be redetermined on July 1, 2004. Thereafter, the borrowing base is scheduled to be redetermined twice each year based on a reserve report provided by the Company to Bank One and the syndicating banks on or before February 15 and August 31 of each year prepared as of the previous November 30 and May 31, respectively. The Revolving Credit Agreement also provides for other special redeterminations in certain circumstances. At each redetermination, Bank One and the syndicating banks redetermine the borrowing base in their sole discretion using customary procedures for evaluating natural gas and oil properties as such exist at the time of each redetermination.

Interest accrues, at Quest Cherokee's option, at either Bank One's "base rate" plus a margin ranging from 1.5% to 2.25% per annum or LIBOR plus a margin ranging from 2.75% to 3.5% per annum, depending upon the ratio of outstanding credit to the borrowing base during the time that any amounts are outstanding under the Term Loan Agreement. After all of the borrowings under the Term Loan Agreement have been repaid, the "base rate" margin decreases to 0.5% to 1.25% per annum and the LIBOR margin decreases to 1.75% to 2.5% per annum, depending upon the ratio of outstanding credit to the borrowing base. Except in certain limited circumstances, the Term Loan Agreement will accrue interest at the rate of LIBOR plus 6% per annum.

Both credit agreements may be repaid at any time. However, if any amount under the Term Loan Agreement is repaid prior to June 22, 2004, a prepayment premium will be required to be paid equal to 2% of the principal amount repaid and if any amount under the Term Loan Agreement in excess of $17.5 million is prepaid during the period from June 23, 2004 to December 24, 2004, a prepayment premium will be required to be paid equal to 1% of such excess amount.

Both of the credit agreements are secured by a lien on the natural gas and oil assets of Quest Cherokee, a pledge of all of the membership interests in Quest Cherokee and a pledge of the membership interest in Bluestem. Bluestem also guaranteed Quest Cherokee's obligations under the credit agreements.

Both of the credit agreements contain affirmative and negative covenants that are typical for credit agreements of this type. The covenants in the two agreements are substantially similar and include provisions of financial and other information; the maintenance of certain financial ratios; restrictions on the incurrence of additional debt; restrictions on the granting of liens; restrictions on making investments; restrictions on making certain restricted payments as described under "—ArcLight Transaction"; restrictions on disposing of assets and merging or consolidating with a third party where Quest Cherokee is not the surviving entity; restrictions on transactions with affiliates that are not on an arms length basis; restrictions on changing the nature of Quest Cherokee's business; and limitations on Quest Cherokee's hedging activities regarding the minimum and maximum amounts of future production that may be hedged.

Both of the credit agreements provide that it is an event of default if a change of control occurs. A "change of control" is defined to include Bluestem no longer being wholly owned by Quest Cherokee; Cherokee Energy Partners ceases to own 100% of the Class A units of Quest Cherokee prior to December 22, 2006; the Company and its wholly owned subsidiaries cease to own 100% of the equity of Quest Cherokee, other than the Class A units; or Mr. Cash ceases to be an executive officer of Quest Cherokee, unless a successor reasonably acceptable to the banks is appointed within 60 days.

ArcLight Transaction

Also in connection with the Devon asset acquisition, the Company received a $51.0 million subordinated note from ArcLight. The note was purchased at par. This note bears interest at 15% per annum and is subordinate and junior in right of payment to the prior payment in full of superior debts. Interest is payable quarterly in arrears; provided, however, that if Quest Cherokee is not permitted to pay cash interest on the note under the terms of its senior debt facilities, then interest will be paid in the form of additional subordinated notes. Quest Cherokee paid a commitment fee of $1,020,000 to obtain this loan. This loan fee has been capitalized as part of the acquisition of assets from Devon. This loan is due along with all accrued and unpaid interest on December 22, 2008. Quest Cherokee has the right to extend the maturity date by an additional two years.

In the event that Quest Cherokee is dissolved on or before December 22, 2006 (an "Early Liquidation Event"), the holders of the subordinated promissory note will be entitled to a make-whole payment equal to the difference between the amount they have received on account of principal and interest on the subordinated promissory note and $76.5 million (150% of the original principal amount of the subordinated promissory note).

In the event of an Early Liquidation Event, the holders of the subordinated promissory notes are entitled to 100% of the net cash flow until they have received the make-whole payment.

As long as any amounts are outstanding under the Bank One Term Loan Agreement, no cash payment of interest and no payments of principal may be made on the subordinated promissory note or with respect to the membership interests in Quest Cherokee, other than certain permitted tax payments. Interest may, however, be paid in the form of the issuance of additional subordinated promissory notes with a principal amount equal to the amount of unpaid interest being paid. After the Bank One Term Loan Agreement has been repaid, payments may be made with respect to the subordinated promissory note only if all of the following conditions have been met:

- no default exists on the date any such payment is made, and no default or event of default would result from the payment , under the Revolving Credit Agreement;
- before and after giving effect to any such payment, the outstanding borrowings under the Revolving Credit Agreement do not exceed 90% of the borrowing base; and
- the total amount paid with respect to the subordinated promissory note and distributed to the equity holders of Quest Cherokee in any 12 month period does not exceed $15 million, unless the ratio of Consolidated Total Debt to EBITDA for the most recent four fiscal quarters is less than 2.0 to 1.0.

In connection with the purchase of the subordinated promissory note, the original limited liability company agreement for Quest Cherokee was amended and restated to, among other things, provide for Class A units and Class B units of membership interest, and ArcLight acquired all of the Class A units of Quest Cherokee in exchange for $100. The existing membership interests in Quest Cherokee owned by the Company's subsidiaries were converted into all of the Class B units.

Under the terms of the amended and restated limited liability company agreement for Quest Cherokee, the net cash flow of Quest Cherokee will generally be distributed 85% to the holders of the subordinated promissory notes and 15% to the holders of the Class B units until the subordinated promissory notes have been repaid. Thereafter, the net cash flow of Quest Cherokee will generally be distributed 60% to the holders of the Class A units and 40% to the holders of the Class B units, until the holders of the subordinated notes and the Class A units have received a combined internal rate of return of 30% on their cash invested. Thereafter, the net cash flow of Quest Cherokee will generally be distributed 30% to the holders of the Class A units and 70% to the holders of the Class B units. These percentages may be altered on a temporary basis as a result of certain permitted tax distributions to the holders of the Class B units; however, future distributions will be shifted from the Class B unit holders to the Class A unit holders until the total distributions are in line with the above percentages. In addition, if the defect value attributable to the properties contributed by the Company's subsidiaries to Quest Cherokee exceed $2.5 million, then any distribution of net cash flow otherwise distributable to the Class B members will, instead, be distributed to the Class A member until these distributions equal such excess amount.

Management Agreement Between QES and Quest Cherokee

As part of the restructuring, QES entered into an operating and management agreement with Quest Cherokee to manage the day to day operations of Quest Cherokee in exchange for a monthly manager's fee of $292,000 plus the reimbursement of costs associated with field employees, first level supervisors, exploration, development and operation of the properties and certain other direct charges. Until Quest Cherokee begins making distributions to its members, the Company's only source of cash flow to pay for its general and administrative expenses will be the management fee paid by Quest Cherokee. Management currently believes that the management fee will be sufficient to cover such expenses for the foreseeable future.

UBS Credit Facility

On July 22, 2004, Quest Cherokee entered into a new syndicated credit facility arranged and syndicated by UBS Securities LLC, with UBS AG, Stamford Branch as agent (the "UBS Credit Agreement"). The UBS Credit Agreement provides for a $120 million six year term loan that was fully funded at closing (the "UBS Term Loan") and a $20 million five year revolving credit facility that can be used to issue letters of credit and fund future working capital needs and general corporate purposes (the "UBS Revolving Loan"). The UBS Credit Agreement also contains a $15 million "synthetic" letter of credit facility that matures in December 2008 in order to provide credit support for Quest Cherokee's natural gas hedging program. A portion of the proceeds from the UBS Term Loan were used to repay the Bank One credit facilities. After the repayment of the Bank One credit facilities and payment of fees and other obligations related to this transaction, Quest Cherokee had approximately $9 million of cash at closing from the proceeds of the UBS Term Loan and $15 million of availability under the UBS Revolving Loan.

Interest accrues under both the UBS Term Loan and the UBS Revolving Loan, at Quest Cherokee's option, at either (i) a rate equal to the greater of the corporate "base rate" established by UBS AG, Stamford Branch, or the federal funds effective rate plus 0.50% (the "Alternative Base Rate"), plus the applicable margin (2.75% for revolving loans and 3.00% for term loans), or (ii) LIBOR, as adjusted to reflect the maximum rate at which any reserves are required to be maintained against Eurodollar liabilities (the "Adjusted LIBOR Rate"), plus the applicable margin (3.75% for revolving loans and 4.00% for term loans). In the event of a default under either the UBS Term Loan or the UBS Revolving Loan, interest will accrue at the applicable rate, plus an additional 2% per annum. Quest Cherokee pays an annual fee on the synthetic letter of credit facility equal to 4.00% of the amount of the facility.

The UBS Credit Agreement may be repaid at any time without any premium or prepayment penalty. An amount equal to $300,000 (0.25% of the original principal balance of the UBS Term Loan) is required to be repaid each quarter, commencing December 31, 2004. In addition, Quest Cherokee is required to semi-annually apply 50% of Excess Cash Flow (or 25% of Excess Cash Flow, if the ratio of the present value (discounted at 10%) of the future cash flows from Quest Cherokee's proved mineral interest to Total Net Debt is greater than or equal to 2.25:1.0) to repay the UBS Term Loan. "Excess Cash Flow" for any semi-annual period is generally defined as net cash flow from operations for that period less (1) principal payments of the UBS Term Loan made during the period, (2) the lower of actual capital expenditures or budgeted capital expenditures during the period and (3) permitted tax distributions made during the period or that will be paid within six months after the period. "Total Net Debt" is generally defined as funded indebtedness less up to $10 million of unrestricted cash.

The UBS Credit Agreement is secured by a lien on the substantially all of the assets of Quest Cherokee (other than the pipeline assets owned by Bluestem) and a pledge of the membership interest in Bluestem. Bluestem also guaranteed Quest Cherokee's obligations under the UBS Credit Agreement.

The UBS Credit Agreement contains affirmative and negative covenants that are typical for credit agreements of this type. The covenants in the UBS Credit Agreement include provisions requiring the maintenance of and furnishing of financial and other information; the maintenance of insurance, the payment of taxes and compliance with the law; the maintenance of collateral and security interests and the creation of additional collateral and security interests; the maintenance of certain financial ratios; restrictions on the incurrence of additional debt or the issuance of convertible or redeemable equity securities; restrictions on the granting of liens; restrictions on making acquisitions and other investments; restrictions on disposing of assets and merging or consolidating with a third party where Quest Cherokee is not the surviving entity; restrictions on the payment of dividends and the repayment of other indebtedness; restrictions on transactions with affiliates that are not on an arms length basis; and restrictions on changing the nature of Quest Cherokee's business.

Under the UBS Credit Agreement, no payments may be made on the ArcLight subordinated promissory note nor may any distributions be made to the members of Quest Cherokee until after the November 30, 2004 reserve report has been delivered to the lenders. After that date, payments may be made with respect to the subordinated promissory note and distributions made to the members of Quest Cherokee semi-annually, but only if all of the following conditions have been met:

- no default exists on the date any such payment is made, and no default or event of default would result from the payment, under the UBS Credit Agreement.
- for the most recent four consecutive quarters, the ratio of the present value (discounted at 10%) of the future cash flows from Quest Cherokee's proved mineral interest to Total Net Debt is at least 1.75:1.0 and the ratio of Total Net Debt to Consolidated EBITDA does not exceed 3.00:1.0, in each case, after giving effect to such payment. "Consolidated EBITDA" is generally defined as consolidated net income, plus interest expense, amortization, depreciation, taxes and non-cash items deducted in computing consolidated net income and minus non-cash items added in computing consolidated net income.
- The amount of such semi-annual payments do not exceed Quest Cherokee's Excess Cash Flow during the preceding half of the fiscal year less (1) the amount of Excess Cash Flow required to be applied to repay the UBS Term Loan, and (2) any portion of the Excess Cash Flow that is used to fund capital expenditures.
- The UBS Credit Agreement provides that it is an event of default if a "change of control" occurs. A "change of control" is defined to include Bluestem, or any other wholly owned subsidiary of Quest Cherokee no longer being wholly owned by Quest Cherokee; ArcLight and the Company collectively ceasing to own at least 51% of the equity interests and voting stock of Quest Cherokee; or Mr. Cash ceasing to be an executive officer of Quest Cherokee, unless a successor reasonably acceptable to UBS AG, Stamford Branch is appointed within 60 days.

In connection with the UBS Credit Agreement, the maturity date of the subordinated promissory note issued to ArcLight was extended to the later of October 22, 2010 and the maturity date of the UBS Term Loan, subject to extension until December 22, 2010.

Wells Fargo Energy Capital Warrant

In connection with the entering into the credit agreement with Wells Fargo Energy Capital on November 7, 2002, the Company issued a warrant to Wells Fargo Energy Capital for 1,600,000 shares of common stock with an exercise price of $0.001 per share. Under the terms of the warrant, the repayment of the Wells Fargo Energy Capital credit agreement on December 22, 2003 in connection with the Devon asset acquisition triggered a put option under the warrant in favor of Wells Fargo Energy Capital. Under the terms of the put option, Wells Fargo Energy Capital may require the Company to purchase the warrant at any time prior to November 7, 2007 for an amount equal to approximately $950,000 (which amount is equal to interest at the rate of 18% per annum on the amounts outstanding under the Wells Fargo Energy Capital credit agreement during its term less any cash interest actually paid to Wells Fargo Energy Capital). In the event that Wells Fargo Energy Capital were to exercise the put option in the near future, the Company may have difficulty satisfying its obligations under the warrant since this obligation was not assumed by Quest Cherokee as part of the restructuring and Quest Resource Corporation does not have any readily available sources of liquidity.

Other Long-Term Indebtedness

The Company has two promissory notes with authorized credit limits of $440,000 and $100,000 each. The $440,000 note matures on February 19, 2008, bears interest at the annual rate of 7% per annum, requires a monthly payment based upon a 60 month amortization, is secured by equipment and rolling stock, and had a principal balance outstanding on May 31, 2004 of $431,000. The $100,000 note matures on November 4, 2004, bears interest at the annual rate of 7% per annum, is secured by the inventory of parts and materials, and had a principal balance outstanding on May 31, 2004 of $100,000. The obligations under this note were assumed by Quest Cherokee as part of the restructuring.

Contractual Obligations

Future payments due on the Company's contractual obligations as of May 31, 2004 are as follows:

	Total	2005	2006-2007	2008-2009	thereafter
Long-term debt	$ 103,700,000	$ --	$ 68,700,000	$ 35,000,000	$ --
Notes payable	1,327,000	286,000	603,000	438,000	--
Convertible debentures	50,000	--	50,000	--	--
Subordinated debt	54,459,000	--	--	54,459,000	--
Total	$ 159,536,000	$ 286,000	$ 69,353,000	$ 89,897,000	$ --

Critical Accounting Policies

The consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States. As such, the Company is required to make certain estimates, judgments and assumptions that it believes are reasonable based upon the information available. These estimates and assumptions affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. A summary of the significant accounting policies is described in Note 1 to the audited financial statements.

Certain Capital Transactions

During the 2004 fiscal year, the Company engaged in the following capital transactions:

Effective June 1, 2003, the Company consummated the Perkins/Willhite acquisition. See Items 1 and 2. "Description of Business and Properties—Recent Developments—Other Acquisitions." A portion of the purchase price for this acquisition was paid through the issuance of 500,000 shares of common stock.

On September 1, 2003, the Company issued 22,650 shares of common stock to four individuals as payment for approximately $62,483 worth of services rendered to the Company.

On September 8, 2003, the Company issued 147,059 shares of common stock for $500,000 in order to satisfy working capital needs.

On May 1, 2004, the Company issued 10,500 shares of common stock to one individual as payment for approximately $31,080 worth of services rendered to the Company.

On May 1, 2004, the Company issued 80,888 shares of common stock to the Company's 401(k) plan valued at $121,331.

During fiscal year 2004, $180,000 of existing debentures were converted into 71,010 shares of common stock. Although the conversion of these debentures did not result in any additional capital being available to the Company, it did cease the accrual of additional interest under the debentures.

Off-balance Sheet Arrangements

At May 31, 2004, the Company did not have any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, the Company does not engage in trading activities involving non-exchange traded contracts. As such, the Company is not exposed to any financing, liquidity, market, or credit risk that could arise if the Company had engaged in such activities.

ITEM 7. FINANCIAL STATEMENTS

Please see the accompanying financial statements attached hereto beginning on page F-1.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Quest Resource Corporation

We have audited the accompanying consolidated balance sheet of QUEST RESOURCE CORPORATION and subsidiaries as of May 31, 2004, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended May 31, 2004 and 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Quest Resource Corporation and subsidiaries as of May 31, 2004, and the consolidated results of their operations and cash flows for the years ended May 31, 2004 and 2003, in conformity with accounting principles generally accepted in the United States of America.

/S/ MURRELL, HALL, MCINTOSH & CO., PLLP

Oklahoma City, Oklahoma
September 16, 2004

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

QUEST RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
May 31, 2004

ASSETS

Current assets:	
Cash	$ 3,508,000
Accounts receivable, trade	7,097,000
Other receivables	609,000
Deposits on acquisition	216,000
Other current assets	257,000
Inventory	492,000
Total current assets	12,179,000
Property and equipment, net of accumulated depreciation of $832,000 and $548,000, respectively	2,570,000
Pipeline assets, net of accumulated depreciation of $1,774,000 and $1,223,000, respectively	36,488,000
Oil and gas properties:	
Properties being amortized	123,161,000
Properties not being amortized	24,662,000
	147,823,000
Less: Accumulated depreciation, depletion and amortization	(8,881,000)
Net property, plant and equipment	138,942,000
Other assets	196,000
Total assets	$ 190,375,000

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities:	
Accounts payable	$ 3,714,000
Revenue payable	3,285,000
Accrued expenses	462,000
Current portion of notes payable	336,000
Short-term derivative liability	10,087,000
Total current liabilities	17,884,000
Non-current liabilities:	
Long-term derivative liability	9,701,000
Asset retirement obligation	717,000
Convertible debentures	50,000
Acquisition holdback payable	638,000
Notes payable	105,027,000
Less current maturities	(336,000)
Non-current liabilities	115,797,000
Subordinated debt (including accrued interest)	54,459,000
Total liabilities	188,140,000
Commitments and contingencies	--
Stockholders' equity:	
10% convertible preferred stock, $.001 par value, 50,000,000 shares authorized, 10,000 shares issued and outstanding in 2004 and 2003	--
Common stock, $.001 par value, 950,000,000 shares authorized, 14,112,694 and 13,280,587 shares issued and outstanding in 2004 and 2003	14,000
Additional paid-in capital	16,642,000
Accumulated other comprehensive income	(10,629,000)
Accumulated deficit	(3,792,000)
Total stockholders' equity	2,235,000
Total liabilities and stockholders' equity	$ 190,375,000

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

QUEST RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED MAY 31,

	2004	2003 (Restated)
Revenue:		
Oil and gas sales	$ 28,147,000	$ 8,345,000
Gas pipeline revenue	2,707,000	632,000
Other revenue and expense	(843,000)	(879,000)
Total revenues	30,011,000	8,098,000
Costs and expenses:		
Oil and gas production	6,835,000	1,923,000
Pipeline operating	3,506,000	912,000
General and administrative expenses	2,555,000	977,000
Depreciation, depletion and amortization	7,650,000	1,822,000
Other costs of revenues	--	56,000
Total costs and expenses	20,546,000	5,690,000
Operating income	9,465,000	2,408,000
Other income (expense):		
Change in derivative fair value	(2,013,000)	(4,867,000)
Sale of assets	(6,000)	(3,000)
Interest expense	(8,057,000)	(727,000)
Interest income	1,000	--
Total other income and expense	(10,075,000)	(5,597,000)
Loss before income taxes	(610,000)	(3,189,000)
Income tax benefit (expense)	245,000	(374,000)
Net loss before cumulative effect of accounting change	(365,000)	(3,563,000)
Cumulative effect of accounting change, net of income taxes of $19,000	(28,000)	--
Net loss	(393,000)	(3,563,000)
Preferred stock dividends	(10,000)	(10,000)
Net loss available to common shareholders	$ (403,000)	$ (3,573,000)
Loss per common share – basic:		
Loss before cumulative effect of accounting change	$ (0.03)	$ (0.35)
Cumulative effect of accounting change	--	--
	$ (0.03)	$ (0.35)
Loss per common share – diluted:		
Loss before cumulative effect of accounting change	$ (0.03)	$ (0.35)
Cumulative effect of accounting change	--	--
	$ (0.03)	$ (0.35)
Weighted average common and common equivalent shares outstanding:		
Basic	13,970,880	10,236,288
Diluted	13,970,880	10,236,288

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

QUEST RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED MAY 31,

	2004	2003 (Restated)
Cash flows from operating activities:		
Net income (loss)	$ (393,000)	$ (3,563,000)
Adjustments to reconcile net income to cash provided by operations:		
Depreciation	835,000	210,000
Depletion	6,802,000	1,612,000
Accrued interest subordinated note	3,459,000	--
Change in derivative fair value	2,013,000	4,867,000
Cumulative effect of accounting change	47,000	--
Deferred income taxes	(263,000)	1,075,000
Accretion of line of credit	1,204,000	139,000
Stock issued for retirement plan	121,000	--
Stock issued for director fees	--	62,000
Stock issued for services	94,000	73,000
Amortization of loan origination fees	172,000	20,000
Other	44,000	--
Change in assets and liabilities:		
Accounts receivable	(4,751,000)	(295,000)
Other receivables	(1,432,000)	(8,000)
Other current assets	(257,000)	--
Futures contract	--	46,000
Inventory	(244,000)	(157,000)
Other assets	(393,000)	(192,000)
Accounts payable	2,302,000	(636,000)
Revenue payable	2,221,000	557,000
Accrued expenses	223,000	209,000
Net cash provided by operating activities	11,804,000	4,019,000
Cash flows from investing activities:		
Acquisition of proved oil and gas properties-Devon	(111,849,000)	--
Acquisition of gas gathering pipeline – Devon	(21,964,000)	--
Deposit on acquisition	--	(613,000)
Equipment, development and leasehold costs	(12,628,000)	(7,999,000)
Net cash used in investing activities	(146,441,000)	(8,612,000)
Cash flows from financing activities:		
Long term debt	105,000,000	6,573,000
Repayments of note borrowings	(21,682,000)	--
Proceeds from subordinated debt	51,000,000	--
Convertible debentures	--	165,000
Change in other long-term liabilities	638,000	--
Common stock	500,000	467,000
Net cash provided by financing activities	135,456,000	7,205,000
Net increase (decrease) in cash	819,000	2,612,000
Cash, beginning of period	2,689,000	77,000
Cash, end of period	$ 3,508,000	$ 2,689,000

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

QUEST RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED MAY 31, 2004 AND 2003 (RESTATED)

	Preferred Shares	Common Shares	Preferred Stock Par Value	Common Stock Par Value	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Deficit	Total
Balance, May 31, 2002	10,000	6,596,140	$ --	$ 6,000	$ 4,442,000	$ --	$ 164,000	$ 4,612,000
Stock sales for cash		47,858			61,000			61,000
Stock issued for director fees		60,000			62,000			62,000
Stock issued for acquisition		5,380,785		5,000	7,343,000			7,348,000
Stock issued for assets		330,000			343,000			343,000
Stock issued for leases		11,775			10,000			10,000
Stock issued for services		70,000			73,000			73,000
Stock issued for convertible debt		378,029		1,000	446,000			447,000
Stock issued for options		406,000		1,000	405,000			406,000
Wells Fargo warrant					1,343,000			1,343,000
Net income							(3,563,000)	(3,563,000)
Balance, May 31, 2003 (Restated)	10,000	13,280,587	$ --	$ 13,000	$ 14,528,000	$ --	$ (3,399,000)	$ 11,142,000
Comprehensive income:								
Net loss							(393,000)	(393,000)
Other comprehensive loss, net of tax:								
Change in fixed-price contract and other derivative fair value						(10,044,000)		(10,044,000)
Reclassification adjustments-contract settlements						(585,000)		(585,000)
Total comprehensive loss								(11,022,000)
Stock sales for cash		147,059			500,000			500,000
Stock issued for acquisition		500,000		1,000	1,219,000			1,220,000
Stock issued for services		33,150			94,000			94,000
Stock issued for convertible debt		71,010			180,000			180,000
Stock issued employees 401(k) plan		80,888			121,000			121,000
Balance, May 31, 2004	10,000	14,112,694	$ --	$ 14,000	$ 16,642,000	$ (10,629,000)	$ (3,792,000)	$ 2,235,000

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Nature of Business

Quest Resource Corporation ("the Company") is an independent energy company with an emphasis on the acquisition, production, transportation, exploration, and development of natural gas (coalbed methane) in southeastern Kansas and northeastern Oklahoma. Quest operations are currently focused on developing coalbed methane gas production in a ten county region that is served by a Company-owned pipeline network.

Principles of Consolidation and Subsidiaries

The Company's subsidiaries consist of:

- Quest Cherokee, LLC, a Delaware limited liability company ("Quest Cherokee"),
- Bluestem Pipeline, LLC, a Delaware limited liability company ("Bluestem"),
- Quest Energy Service, Inc., a Kansas corporation ("QES"),
- Quest Oil & Gas Corporation, a Kansas corporation ("QOG"),
- Ponderosa Gas Pipeline Company, a Kansas corporation ("PGPC"),
- Producers Service, Incorporated, a Kansas corporation ("PSI"),
- J-W Gas Gathering, L.L.C., a Kansas limited liability ("J-W Gas"), and
- STP Cherokee, Inc., an Oklahoma corporation ("STP").

QES, QOG, PGPC and STP are wholly owned by the Company. PGPC owns all of the outstanding capital stock of PSI and PSI is the sole member of J-W Gas. QES, QOG, PGPC, STP, PSI and J-W Gas collectively own all of the outstanding Class B Units of Quest Cherokee. Cherokee Energy Partners, LLC, a wholly owned subsidiary of ArcLight Energy Partners Fund I, L.P. ("ArcLight"), owns all of the Class A Units of Quest Cherokee. Quest Cherokee is the sole member of Bluestem.

Quest Cherokee owns and operates all of the Company's Cherokee Basin natural gas and oil properties and vehicles and equipment. The Company's natural gas gathering pipeline assets in the Cherokee Basin are owned by Bluestem. QES employs all of the Company's employees and has entered into an operating and management agreement with Quest Cherokee to manage the day to day operations of Quest Cherokee in exchange for a monthly manager's fee of $292,000 plus the reimbursement of costs associated with field employees, first level supervisors, exploration, development and operation of the properties and certain other direct charges (the "Management Agreement"). STP owns properties located in Kentucky, Texas and Oklahoma outside of the Cherokee Basin, and QES and STP own certain equipment used at the corporate headquarters offices.

Quest Cherokee, has two classes of membership units, Class A that is controlled by ArcLight, and Class B that is owned and controlled by Quest Resource Corporation though several of its wholly owned subsidiaries. The Class A member made a capital contribution of $100 and the Class B members contributed natural gas and oil properties with an agreed upon value of $51 million. ArcLight also made a $51 million subordinated loan to Quest Cherokee. For financial reporting purposes, the properties transferred to Quest Cherokee by the Company and its subsidiaries, were transferred at historical cost.

Under the terms of the amended and restated limited liability company agreement for Quest Cherokee, the net cash flow of Quest Cherokee will generally be distributed 85% to the holders of the subordinated promissory note and 15% to the holders of Class B units until the subordinated promissory note has been repaid. Thereafter, the net cash flow of Quest Cherokee will generally be distributed 60% to the holders of the Class A units and 40% to the holders of the Class B units, until the holders of the subordinated notes and the Class A units have received a combined internal rate of return of 30% on their cash invested. Thereafter, the net cash flow of Quest Cherokee will generally be distributed 30% to the holders of the Class A units and 70% to the holders of the Class B units.

Since the Company is anticipated to ultimately receive 70% of the cash flows remaining, after retirement of the subordinated note including accrued interest and after payments to ArcLight to achieve their internal rate of return of 30%, the Quest Cherokee financials have been included in these consolidated financial statements. For the period from inception through May 31, 2004, Quest Cherokee incurred operating losses. Operating losses are allocated 30% to the minority members until their membership interest of $100 is reduced to zero, thereafter all losses are allocated 100% to the Company.

Financial reporting by the Company's subsidiaries is consolidated into one set of financial statements for QRC.

Investments in which the Company does not have a majority voting or financial controlling interest are accounted for under the equity method of accounting unless its ownership constitutes less than a 20% interest in such entity for which such investment would then be included in the consolidated financial statements on the cost method. All significant inter-company transactions and balances have been eliminated in consolidation.

QES provides all of the service activities required for the operation and development of QOG's natural gas and oil properties and the natural gas pipelines owned by PGPC.

PGPC's primary assets are one hundred and sixty miles of natural gas gathering pipelines throughout southeastern Kansas.

Investments in which the Company does not have a majority voting or financial controlling interest are accounted for under the equity method of accounting unless its ownership constitutes less than a 20% interest in such entity for which such investment would then be included in the consolidated financial statements on the cost method. All significant inter-company transactions and balances have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Basis of Accounting

The Company's financial statements are prepared using the accrual method of accounting. Revenues are recognized when earned and expenses when incurred.

Uninsured Cash Balances

The Company maintains its cash balances at several financial institutions. Accounts at the institutions are insured by the Federal Deposit Insurance Corporation up to $100,000. Periodically, the Company's cash balances are in excess of this amount.

Accounts Receivable

The Company conducts the majority of its operations in the States of Kansas and Oklahoma and operates exclusively in the natural gas and oil industry. The Company's joint interest and natural gas and oil sales receivables are generally unsecured; however, the Company has not experienced any significant losses to date. Receivables are recorded at the estimate of amounts due based upon the terms of the related agreements.

Management periodically assesses the Company's accounts receivable and establishes an allowance for estimated uncollectible amounts. Accounts determined to be uncollectible are charged to operations when that determination is made.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in cash and derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing natural gas and oil. These arrangements expose us to credit risk from our counterparties. Our accounts receivable are primarily from purchasers of natural gas and oil products. Natural gas sales to one purchaser (ONEOK) accounted for more than 90% of total natural gas and oil revenues for fiscal year 2004. The industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions.

Natural Gas and Oil Properties

The Company follows the full cost method of accounting for natural gas and oil properties, prescribed by the Securities and Exchange Commission ("SEC"). Under the full cost method, all acquisition, exploration, and development costs are capitalized. The Company capitalizes internal costs including: salaries and related fringe benefits of employees directly engaged in the acquisition, exploration and development of natural gas and oil properties, as well as other directly identifiable general and administrative costs associated with such activities.

All capitalized costs of natural gas and oil properties, including the estimated future costs to develop proved reserves, are amortized on the units-of-production method using estimates of proved reserves. Investments in unproved reserves and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Abandonment's of natural gas and oil properties are accounted for as adjustments of capitalized costs; that is, the cost of abandoned properties is charged to the full cost pool and amortized.

Under the full cost method, the net book value of natural gas and oil properties, less related deferred income taxes, may not exceed a calculated "ceiling". The ceiling is the estimated after-tax future net revenue from proved natural gas and oil properties, discounted at 10% per annum plus the lower of cost or fair market value of unproved properties. In calculating future net revenues, prices and costs in effect at the time of the calculation are held constant indefinitely, except for changes that are fixed and determinable by existing contracts. The net book value is compared to the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an expense.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between the capitalized costs and proved reserves of natural gas and oil, in which case the gain or loss is recognized in income.

Other Property and Equipment

Other property and equipment are stated at cost. Depreciation is calculated using the straight-line method for financial reporting purposes and accelerated methods for income tax purposes.

The estimated useful lives are as follows:

Buildings	25 years	Pipeline	40 years
Equipment	10 years	Vehicles	7 years

Other Dispositions

Upon disposition or retirement of property and equipment other than natural gas and oil properties, the cost and related accumulated depreciation are removed from the accounts and the gain or loss thereon, if any, is credited or charged to income.

Marketable Securities

In accordance with Statement of Financial Accounting Standards ("SFAS") 115, *Accounting for Certain Investments in Debt and Equity Securities*, the Company classifies its investment portfolio according to the provisions of SFAS 115 as either held to maturity, trading, or available for sale. At May 31, 2004, the Company did not have any investments in its investment portfolio classified as available for sale and held to maturity.

Income Taxes

The Company accounts for income taxes pursuant to the provisions of the SFAS 109, *Accounting for Income Taxes*, which requires an asset and liability approach to calculating deferred income taxes. The asset and liability approach requires the recognition of deferred tax liabilities and assets for the expected future tax consequences of temporary differences between the carrying amounts and the tax basis of assets and liabilities. The provision for income taxes differ from the amounts currently payable because of temporary differences (primarily intangible drilling costs and the net operating loss carry forward) in the recognition of certain income and expense items for financial reporting and tax reporting purposes.

Earnings Per Common Share

SFAS 128, *Earnings Per Share*, requires presentation of "basic" and "diluted" earnings per share on the face of the statements of operations for all entities with complex capital structures. Basic earnings per share is computed by dividing net income by the weighted average number of common shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted during the period. Dilutive securities having an anti-dilutive effect on diluted earnings per share are excluded from the calculation. See Note 10 – Earnings Per Share for a reconciliation of the numerator and denominator of the basic and diluted earnings per share computations.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash, receivables, deposits, hedging contracts, accounts payable, accrued expenses, convertible debentures and notes payable. The carrying amount of cash, receivables, deposits, accounts payable and accrued expenses approximates fair value because of the short-term nature of those instruments. The hedging contracts are recorded in accordance with the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. The carrying amounts for convertible debentures and notes payable approximate fair value because the interest rates have remained generally unchanged since the issuance of the convertible debentures and due to the variable nature of the interest rates of the notes payable.

Stock-Based Compensation

The Company applies the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion ("APB") 25, *Accounting for Stock Issued to Employees*, and related interpretations including Financial Accounting Standards Board Interpretation ("FIN") 44, *Accounting for Certain Transactions Involving Stock Compensation*, an interpretation of APB 25, to account for non-plan stock options granted to employees and non-employee directors. Under this method, compensation expense is recorded on the date of grant only if the fair value of the underlying stock exceeded the exercise price, and is amortized ratably over the service period. As required by FIN 44, the Company uses a fair value based method to account for stock options granted to service providers.

SFAS 123, *Accounting for Stock-Based Compensation*, and SFAS 148, *Accounting for Stock-Based Compensation-Transition and Disclosure*, established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS 123, the Company has elected to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS 148. Since May 31, 2003, there have been no outstanding stock options issued by the Company.

Accounting for Derivative Instruments and Hedging Activities

The Company seeks to reduce its exposure to unfavorable changes in natural gas prices by utilizing energy swaps and collars (collectively fixed-price contracts). In the first quarter of fiscal 2001, the Company adopted SFAS 133, as amended by SFAS 138, *Accounting for Derivative Instruments and Hedging Activities,* which established new accounting and reporting guidelines for derivative instruments and hedging activities. It requires that all derivative instruments be recognized as assets or liabilities in the statement of financial position, measured at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but redesignation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS 133, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings.

Pursuant to the provisions of SFAS 133, all hedging designations and the methodology for determining hedge ineffectiveness must be documented at the inception of the hedge, and, upon the initial adoption of the standard, hedging relationships must be designated anew. Based on the interpretation of these guidelines by the Company, the changes in fair value of all of its derivatives during the period from June 1, 2003 to December 22, 2003 were required to be reported in results of operations, rather than in other comprehensive income.

Although the Company's fixed-price contracts may not qualify for special hedge accounting treatment from time to time under the specific guidelines of SFAS 133, the Company has continued to refer to these contracts in this document as hedges inasmuch as this was the intent when such contracts were executed, the characterization is consistent with the actual economic performance of the contracts, and the Company expects the contracts to continue to mitigate its commodity price risk in the future. The specific accounting for these contracts, however, is consistent with the requirements of SFAS 133. See Note 17 – Derivatives.

The Company has established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently evaluated internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility, and time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

Asset Retirement Obligations

Effective June 1, 2003, the Company adopted SFAS 143, *Accounting for Asset Retirement Obligations*. SFAS 143 requires companies 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. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. The Company's asset retirement obligations relate to the plugging and abandonment of natural gas and oil properties.

Reclassification

Certain reclassifications have been made to the prior year's financial statements in order to conform to the current presentation.

2. Restatement of Financial Statements

The Company restated its financial statements for the fiscal year ended May 31, 2003. This restatement of the Company's financial statements was reported in Amendment No. 2 to the Company's Annual Report on Form 10-KSB/A for the fiscal year ended May 31, 2003.

This restatement of the financial statements corrects the reporting of certain transactions and further reflects the correct adoption and application of the following accounting pronouncements:

- SFAS 128, *Earnings per Share*
- SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*
- SFAS 143, *Accounting for Asset Retirement Obligations*
- Accounting Research Bulletin No. 51, *Consolidated Financial Statements*
- SFAS 94, *Consolidation of All Majority-Owned Subsidiaries*
- SFAS 109, *Accounting for Income Taxes*
- SFAS 123, *Accounting for Stock-Based Compensation*

The effect of the restatement of the financial statements on the net income (loss) for the fiscal year ended May 31, 2003 is as follows as set forth below:

	As Restated	As Previously Reported
Statement of Operations data for the year ended May 31, 2003:		
Total revenues	$ 8,098,000	$ 11,730,000
Total expenses	6,420,000	9,030,000
Income before income taxes and change in derivative fair value	1,678,000	2,700,000
Change in derivative fair value	(4,867,000)	--
Income (loss) before income taxes	(3,189,000)	2,700,000
Income tax expense	(374,000)	(997,000)
Net income (loss)	$ (3,563,000)	$ 1,703,000

The effect of the restatement of the financial statements on the net income (loss) per share for the fiscal year ended May 31, 2003 is as follows as set forth below:

	As Restated	As Previously Reported
Statement of Operations data for the year ended May 31, 2003:		
Net income (loss) per common share - basic	($0.35)	$0.17
Net income (loss) per common share - diluted	($0.35)	$0.17

The effect of the restatement of the financial statements on the Balance Sheet for the fiscal year ended May 31, 2003 is as follows as set forth below:

	As Restated	As Previously Reported
Balance Sheet data as of May 31, 2003:		
Total assets	$ 36,533,000	$ 35,106,000
Total liabilities	$ 25,391,000	$ 21,792,000
Total stockholders' equity	$ 11,142,000	$ 13,314,000

3. Acquisitions

On December 10, 2003, the Company entered into an asset purchase agreement with Devon Energy Production Company, L.P. and Tall Grass Gas Services, LLC (collectively "Devon") to acquire certain natural gas properties located in Kansas and Oklahoma for a total consideration of $126 million, subject to certain purchase price adjustments. The acquisition was finalized on December 22, 2003. At the closing, the Company transferred all of its rights and obligations under the asset purchase agreement to Quest Cherokee.

At the time of closing, Devon had not received consents to the assignment of certain of the leases from the lessors on natural gas leases with an allocated value of approximately $12.3 million. As a result, Quest Cherokee and

Devon entered into a Holdback Agreement pursuant to the terms of which Quest Cherokee paid approximately $113.4 million of the purchase price at the closing and agreed to pay the allocated value of the remaining properties at such time as Devon received the consents to assignment for those leases. Subsequent to closing, Quest Cherokee paid approximately $9.6 million in February 2004 and $2.6 million in May 2004. As of May 31, 2004, approximately $600,000 was included on the balance sheet as acquisition holdback payable pending final review. This amount was classified as a non-current liability since the payment will be funded with long-term financing.

At the time of acquisition, the acquired assets had approximately 95.9 Bcfe of estimated proved reserves, 91.7 Bcfe of estimated probable reserves and 72.2 Bcfe of estimated possible reserves. The assets included approximately 372,000 gross (366,000 net) acres of natural gas leases, 418 gross (325 net) natural gas wells and 207 miles of natural gas gathering pipelines. At the time of acquisition, the Devon assets were producing an average of approximately 19,600 mcf per day.

In accordance with the terms of the asset purchase agreement, the purchase price, including approximately $7.7 million of transaction fees and $1.7 million of assumed hedging liabilities was allocated as follows:

Proved producing properties	$54,528,000
Proved undeveloped properties	38,649,000
Undeveloped properties	20,422,000
Pipelines	21,964,000
Other	9,000
Total	$135,572,000

See the Current Report on Form 8-K filed by the Company on January 6, 2004 for additional information regarding the Devon acquisition.

Effective June 1, 2003, PGPC and the Company consummated a Stock Purchase Agreement with Perkins Oil Enterprises, Inc. and E. Wayne Willhite Energy, L.L.C. pursuant to the terms of which the Company and PGPC acquired from Perkins Oil Enterprises and E. Wayne Willhite Energy all of the capital stock of PSI in exchange for 500,000 shares of the common stock of the Company which was valued at $1.2 million. At the time of the acquisition, PSI owned all of the issued and outstanding membership interests of J-W Gas and a 5-year contract right to operate a lease on a 78-mile natural gas pipeline and J-W Gas owned approximately 200 miles of natural gas gathering lines in southeast Kansas. These assets were subsequently transferred to Quest Cherokee as part of the restructuring of the Company's operations in anticipation of the Devon acquisition.

Also effective June 1, 2003, QOG closed on a Purchase and Sale Agreement with James R. Perkins Energy, L.L.C. and E. Wayne Willhite Energy, L.L.C. and J-W Gas pursuant to the terms of which QOG acquired 53 natural gas and oil leases and related assets in Chautauqua, Elk, and Montgomery Counties, Kansas for $2,000,000. Both of these June 6, 2003 transactions were completed effective as of June 1, 2003. The cash portion of the purchase price was funded with borrowings under its two credit facilities with Wells Fargo Bank Texas, N.A. and Wells Fargo Energy Capital, Inc. These assets were also subsequently transferred to Quest Cherokee as part of the restructuring of the Company's operations in anticipation of the Devon acquisition.

In accordance with the terms of the asset purchase agreement, the purchase price, current assets and certain assumed liabilities were allocated as follows:

Current assets	$ 604,000
Property and equipment	1,177,000
Natural gas and oil properties	2,040,000
Current liabilities	(669,000)
Long-term debt	(112,000)
Total	$ 3,040,000

On November 7, 2002, the Company, STP and Mr. Cash, the sole stockholder of STP, consummated an Agreement and Plan of Reorganization by and among the Company, STP and Mr. Cash, dated as of November 7, 2002 (the "Reorganization Agreement"). Pursuant to the terms and conditions of the Reorganization Agreement, the Company issued to Mr. Cash 5,380,785 shares of the common stock of the Company, representing approximately 42.0% of the common stock of the Corporation after giving effect to the transactions contemplated by the Reorganization Agreement, in exchange for 100% of the outstanding common stock of STP (the "Stock Exchange"). The transaction is being accounted for as a "purchase" following the procedures of SFAS 142, "Accounting for Business Combinations". These assets were also subsequently transferred to Quest Cherokee as part of the restructuring of the Company's operations in anticipation of the Devon acquisition

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition:

Current assets	$ 1,667,000
Fixed assets	15,497,000
Current liabilities	(1,620,000)
Debt assumed	(8,196,000)
Net assets acquired	$ 7,348,000

Pro Forma Summary Data (unaudited)

The following pro forma summary data for the years ending May 31, 2004 and 2003 presents the consolidated results of operations as if the Devon property acquisition made on December 22, 2003, the Perkins/Willhite acquisition made on June 1, 2003 and the STP acquisition made on November 7, 2002 had occurred on June 1, 2002. These pro forma results have been prepared for comparative purposes only and do not purport to be indicative of what would have occurred had the acquisitions been made at June 1, 2002 or of results that may occur in the future. For additional information regarding the Devon property acquisition and the related transactions, please see the Company's Form 8-K filed January 06, 2004.

	Years Ended May 31,	
	2004	2003
Proforma revenue	$ 45,241,000	$ 26,033,000
Proforma net income	$ 2,311,000	$ 67,000
Proforma net income per share	$ 0.17	$ 0.01

4. Long-Term Debt

Long-term debt consists of the following:	May 31, 2004
Senior credit facility:	
Revolving loan	$ 68,700,000
Term Loan	35,000,000
Notes payable to banks and finance companies, secured by equipment and vehicles, due in installments through February 2008 with interest ranging from 5.5% to 11.5% per annum	1,327,000
Convertible debentures – unsecured; interest accrues at 8% per annum	50,000
Total long-term debt	105,077,000
Less - current maturities	336,000
Total long term debt, net of current maturities	$ 104,741,000
Subordinated debt (inclusive of accrued interest)	$ 54,459,000

The aggregate scheduled maturities of notes payable and long-term debt for the five fiscal years ending May 31, 2009 and thereafter were as follows as of May 31, 2004:

2005	$ 286,000
2006	290,000
2007	69,063,000
2008	361,000
2009	89,536,000
thereafter	--
	$ 159,536,000

Bank One Credit Facilities

In connection with the December 22, 2004 Devon asset acquisition, the previous credit facilities with Wells Fargo Bank Texas, N.A. and Wells Fargo Energy Capital, Inc. were paid off. The Company's subsidiary, Quest Cherokee, entered into a Credit Agreement consisting of a three year $200 million senior revolving loan (the "Revolving Credit Agreement") and a five year $35 million senior term second lien secured loan (the "Term Loan Agreement") arranged and syndicated by Banc One Capital Markets, Inc. and with Bank One, NA, as agent.

The Revolving Credit Agreement provided for an initial borrowing base of $57 million, which amount was increased to $70 million upon delivery to the administrative agent of a certificate evidencing that third party consents had been obtained for the assignment of certain natural gas leases from Devon. The borrowing base is scheduled to be redetermined on July 1, 2004. Thereafter, the borrowing base is scheduled to be redetermined twice each year based on a reserve report provided by the Company to Bank One and the syndicating banks on or before February 15 and August 31 of each year prepared as of the previous November 30 and May 31, respectively. The Revolving Credit Agreement also provides for other special redeterminations in certain circumstances. At each redetermination, Bank One and the syndicating banks redetermine the borrowing base in their sole discretion using customary procedures for evaluating natural gas and oil properties as such exist at the time of each redetermination.

Interest accrues, at Quest Cherokee's option, at either Bank One's "base rate" plus a margin ranging from 1.5% to 2.25% per annum or LIBOR plus a margin ranging from 2.75% to 3.5% per annum, depending upon the ratio of outstanding credit to the borrowing base during the time that any amounts are outstanding under the Term Loan Agreement. After all of the borrowings under the Term Loan Agreement have been repaid, the "base rate" margin decreases to 0.5% to 1.25% per annum and the LIBOR margin decreases to 1.75% to 2.5% per annum, depending upon the ratio of outstanding credit to the borrowing base. Except in certain limited circumstances, the Term Loan Agreement will accrue interest at the rate of LIBOR plus 6% per annum.

Both credit agreements may be repaid at any time. However, if any amount under the Term Loan Agreement is repaid prior to June 22, 2004, a prepayment premium will be required to be paid equal to 2% of the principal amount repaid and if any amount under the Term Loan Agreement in excess of $17.5 million is prepaid during the period from June 23, 2004 to December 24, 2004, a prepayment premium will be required to be paid equal to 1% of such excess amount.

Both of the credit agreements are secured by a lien on the natural gas and oil assets of Quest Cherokee, a pledge of all of the membership interests in Quest Cherokee and a pledge of the membership interest in Bluestem. Bluestem also guaranteed Quest Cherokee's obligations under the credit agreements.

Both of the credit agreements contain affirmative and negative covenants that are typical for credit agreements of this type. The covenants in the two agreements are substantially similar and include provisions of financial and other information; the maintenance of certain financial ratios; restrictions on the incurrence of additional debt; restrictions on the granting of liens; restrictions on making investments; restrictions on making certain restricted payments as described under "—ArcLight Transaction"; restrictions on disposing of assets and merging or consolidating with a third party where Quest Cherokee is not the surviving entity; restrictions on transactions with affiliates that are not on an arms length basis;

restrictions on changing the nature of Quest Cherokee's business; and limitations on Quest Cherokee's hedging activities regarding the minimum and maximum amounts of future production that may be hedged.

Both of the credit agreements provide that it is an event of default if a change of control occurs. A "change of control" is defined to include Bluestem no longer being wholly owned by Quest Cherokee; Cherokee Energy Partners ceases to own 100% of the Class A units of Quest Cherokee prior to December 22, 2006; the Company and its wholly owned subsidiaries cease to own 100% of the equity of Quest Cherokee, other than the Class A units; or Mr. Cash ceases to be an executive officer of Quest Cherokee, unless a successor reasonably acceptable to the banks is appointed within 60 days.

ArcLight Transaction

Also in connection with the Devon asset acquisition, the Company received a $51.0 million subordinated note from ArcLight. The note was purchased at par. This note bears interest at 15% per annum and is subordinate and junior in right of payment to the prior payment in full of superior debts. Interest is payable quarterly in arrears; provided, however, that if Quest Cherokee is not permitted to pay cash interest on the note under the terms of its senior debt facilities, then interest will be paid in the form of additional subordinated notes. Quest Cherokee paid a commitment fee of $1,020,000 to obtain this loan. This loan fee has been capitalized as part of the acquisition of assets from Devon. This loan is due along with all accrued and unpaid interest on December 22, 2008. Quest Cherokee has the right to extend the maturity date by an additional two years.

In the event that Quest Cherokee is dissolved on or before December 22, 2006 (an "Early Liquidation Event"), the holders of the subordinated promissory note will be entitled to a make-whole payment equal to the difference between the amount they have received on account of principal and interest on the subordinated promissory note and $76.5 million (150% of the original principal amount of the subordinated promissory note).

In the event of an Early Liquidation Event, the holders of the subordinated promissory notes are entitled to 100% of the net cash flow until they have received the make-whole payment.

As long as any amounts are outstanding under the Bank One Term Loan Agreement, no cash payment of interest and no payments of principal may be made on the subordinated promissory note or with respect to the membership interests in Quest Cherokee, other than certain permitted tax payments. Interest may, however, be paid in the form of the issuance of additional subordinated promissory notes with a principal amount equal to the amount of unpaid interest being paid. After the Bank One Term Loan Agreement has been repaid, payments may be made with respect to the subordinated promissory note only if all of the following conditions have been met:

- no default exists on the date any such payment is made, and no default or event of default would result from the payment , under the Revolving Credit Agreement;
- before and after giving effect to any such payment, the outstanding borrowings under the Revolving Credit Agreement do not exceed 90% of the borrowing base; and
- the total amount paid with respect to the subordinated promissory note and distributed to the equity holders of Quest Cherokee in any 12 month period does not exceed $15 million, unless the ratio of Consolidated Total Debt to EBITDA for the most recent four fiscal quarters is less than 2.0 to 1.0.

In connection with the purchase of the subordinated promissory note, the original limited liability company agreement for Quest Cherokee was amended and restated to, among other things, provide for Class A units and Class B units of membership interest, and ArcLight acquired all of the Class A units of Quest Cherokee in exchange for $100. The existing membership interests in Quest Cherokee owned by the Company's subsidiaries were converted into all of the Class B units.

Under the terms of the amended and restated limited liability company agreement for Quest Cherokee, the net cash flow of Quest Cherokee will generally be distributed 85% to the holders of the subordinated promissory notes and

15% to the holders of the Class B units until the subordinated promissory notes have been repaid. Thereafter, the net cash flow of Quest Cherokee will generally be distributed 60% to the holders of the Class A units and 40% to the holders of the Class B units, until the holders of the subordinated notes and the Class A units have received a combined internal rate of return of 30% on their cash invested. Thereafter, the net cash flow of Quest Cherokee will generally be distributed 30% to the holders of the Class A units and 70% to the holders of the Class B units. These percentages may be altered on a temporary basis as a result of certain permitted tax distributions to the holders of the Class B units; however, future distributions will be shifted from the Class B unit holders to the Class A unit holders until the total distributions are in line with the above percentages. In addition, if the defect value attributable to the properties contributed by the Company's subsidiaries to Quest Cherokee exceed $2.5 million, then any distribution of net cash flow otherwise distributable to the Class B members will, instead, be distributed to the Class A member until these distributions equal such excess amount.

Wells Fargo Energy Capital Warrant

In connection with the entering into the credit agreement with Wells Fargo Energy Capital on November 7, 2002, the Company issued a warrant to Wells Fargo Energy Capital for 1,600,000 shares of common stock with an exercise price of $0.001 per share. Under the terms of the warrant, the repayment of the Wells Fargo Energy Capital credit agreement on December 22, 2003 in connection with the Devon asset acquisition triggered a put option under the warrant in favor of Wells Fargo Energy Capital. Under the terms of the put option, Wells Fargo Energy Capital may require the Company to purchase the warrant at any time prior to November 7, 2007 for an amount equal to approximately $950,000 (which amount is equal to interest at the rate of 18% per annum on the amounts outstanding under the Wells Fargo Energy Capital credit agreement during its term less any cash interest actually paid to Wells Fargo Energy Capital). In the event that Wells Fargo Energy Capital were to exercise the put option in the near future, the Company may have difficulty satisfying its obligations under the warrant since it does not have any readily available sources of liquidity.

Other Long-Term Indebtedness

The Company has two promissory notes with authorized credit limits of $440,000 and $100,000 each. The $440,000 note matures on February 19, 2008, bears interest at the annual rate of 7% per annum, requires a monthly payment based upon a 60 month amortization, is secured by equipment and rolling stock, and had a principal balance outstanding on May 31, 2004 of $431,000. The $100,000 note matures on November 4, 2004, bears interest at the annual rate of 7% per annum, is secured by the inventory of parts and materials, and had a principal balance outstanding on May 31, 2004 of $100,000. The obligations under this note were assumed by Quest Cherokee as part of the restructuring of the Company's operations in anticipation of the acquisition of assets from Devon.

Convertible Debentures

For the year ended May 31, 2002, the Company issued $367,000 of convertible debentures and converted $50,000 of the debentures into 58,723 shares of common stock. For the year ended May 31, 2003, the Company issued $165,000 of convertible debentures and converted $397,000 of debentures into 328,029 shares of common stock. During the year ended May 31, 2004, the Company converted $180,000 of debentures into 71,010 shares of common stock.

Currently one debenture for $50,000 remains outstanding. This debenture has an interest rate of 8%. Interest is paid quarterly. The debenture has a conversion feature that allows the debenture holder to convert to common stock after one year from the date of the debenture but prior to the maturity date. The conversion price is 75% of the daily average trading price of the Company's common stock for the 30 days prior to the conversion with the conversion price limited to a maximum of $3.00 per share and a minimum of $1.25 per share.

5. Stockholders' Equity

Common Stock Transactions

The Company has authorized 950,000,000 shares of common stock and 50,000,000 shares of preferred stock. As of May 31, 2004, there were 14,112,694 shares of common stock outstanding. The following transactions were recorded in the Company's financial statements during the year ended May 31, 2004.

1) Issued 500,000 shares of common stock in connection with the Perkins/Willhite acquisition.
2) Issued 71,010 shares of common stock upon the conversion of $180,000 in convertible debentures.
3) Issued 33,150 shares of common stock to four individuals for services rendered.
4) Issued 147,059 shares of common stock for working capital.
5) Issued 80,888 shares of common stock to employees 401(k) plan.

The following transactions were recorded in the Company's financial statements during the year ended May 31, 2003.

1) Issued 5,380,785 shares of common stock in connection with the STP acquisition.
2) Issued 328,029 shares of common stock upon the conversion of $397,000 in convertible debentures.
3) Issued 50,000 shares of common stock to repay a $50,000 promissory note.
4) Issued 60,000 shares of common stock to compensate directors for four years of service.
5) Issued 70,000 shares to two individuals for services rendered during previous four years.
6) Issued 330,000 shares of common stock for assets valued at $343,000.
7) Issued 11,775 shares for leasehold cost in conjunction with the purchase of natural gas & oil leases.
8) Issued 47,858 shares of common stock for $61,000 in cash.
9) Issued 406,000 shares of common stock for $406,000 in cash upon exercise of stock options.

Series A Preferred Stock

The Company has authorized 50,000,000 preferred shares of stock. During the year ended May 31, 2000, the Company issued a total of 10,000 shares of Series A Preferred Stock to two individuals for a total of $100,000. Each share of Series A Preferred Stock is convertible into four shares of common stock. The Series A Preferred Stock has an annual cash dividend of $1.00 per share. 10,000 shares of Series A Preferred Stock remain issued and outstanding as of May 31, 2004.

Other comprehensive income

The components of other comprehensive income and related tax effects for the year ended May 31, 2004 are shown as follows:

	Gross	Tax Effect	Net of Tax
Change in fixed-price contract and other derivative fair value	$ (11,132,000)	$ (1,088,000)	$ (10,044,000)
Reclassification adjustments – contract settlements	(649,000)	(64,000)	(585,000)
	$ (11,781,000)	$ (1,152,000)	$ (10,629,000)

6. Income Taxes

The components of income tax expense for the fiscal years ended May 31, 2004 and 2003 are as follows:

	Years Ended May 31, 2004	Years Ended May 31, 2003 (Restated)
Current tax expense:		
Federal	$ --	$ --
State	--	--
	--	--
Deferred tax expense:		
Federal	(208,000)	318,000
State	(37,000)	56,000
	(245,000)	374,000
	$ (245,000)	$ 374,000

A reconciliation of income tax at the statutory rate to the Company's effective rate for the fiscal years ended May 31, 2004 and 2003 is as follows:

	2004	2003 (Restated)
Computation of deferred income tax expense (benefit) at statutory rate	$ (245,000)	$ (980,000)
Loss of available net operating loss carry-forwards due to ownership changes	--	1,430,000
Other	--	(76,000)
	$ (245,000)	$ 374,000

The following temporary differences gave rise to the net deferred tax liabilities at May 31, 2004 and 2003:

	2004	2003 (Restated)
Deferred tax liabilities, non-current:		
Book basis in property and equipment in excess of tax basis, net of accumulated depreciation, depletion, and amortization	$ 2,686,000	$ 3,362,000
Deferred tax assets, current:		
Hedging contracts expensed per books but deferred for income tax reporting purposes	(2,752,000)	(1,947,00 0)
Other	66,000	--
	$ --	$ 1,415,000

The step up in value of the natural gas and oil property basis recorded in connection with the STP merger resulted in the recognition of a tax benefit of approximately $623,000 for financial reporting purposes, but does not create a benefit for tax purposes. At May 31, 2004 the Company had federal income tax net operating loss (NOL) carryforwards of approximately $2,326,000. The NOL carryforwards expire from 2021 through 2023. The value of these carryforwards depends on the ability of the Company to generate taxable income.

The ability of the Company to utilize NOL carryforwards to reduce future federal taxable income and federal income tax of the Company is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock by the Company during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of the Company.

7. Related Party Transactions

The corporate headquarters for the Company and its subsidiaries is located in Suite 300 at 9520 N. May Avenue in Oklahoma City, OK 73120. Prior to July 2004, the offices were located at Suite 200 at 5901 N. Western in Oklahoma City, Oklahoma 73118 and the space was rented from Mr. Cash, who is the Chairman, Co-Chief Executive Officer and a director of the Company for the amount of $3,050 monthly.

An administrative office for the Company and its subsidiaries is rented from Crown Properties, LC for $400 per month. Crown Properties, LC is owned by Marsha K. Lamb who is the wife of Mr. Lamb, the Co-Chief Executive Officer, President, and a director of the Company.

8. Supplemental Cash Flow Information

	Years Ended May 31,	
	2004	2003
Cash paid for interest	$ 3,354,000	$ 515,000
Cash paid for income taxes	$ --	$ --

Supplementary Information:

During the year ended May 31, 2004, non-cash investing and financing activities are as follows:

1) Issued stock upon conversion of $180,000 of convertible debentures.
2) Issued stock to acquire assets valued at $1,200,000.
3) Issued stock for services rendered valued at $94,000.
4) Issued stock to the Company's 401(k) plan valued at $121,000
5) Recorded non-cash additions to net natural gas and oil properties of $624,000 pursuant to SFAS 143.

During the year ended May 31, 2003, non-cash investing and financing activities are as follows:

1) Issued stock upon conversion of $447,000 of convertible debentures.
2) Issued stock to acquire marketing business valued at $343,000.
3) Issued stock in reorganization valued at $7,348,000.
4) Issued stock to acquire leases valued at $10,000.
5) Issued stock for director fees and services valued at $135,000.

9. Contingencies

Like other natural gas and oil producers and marketers, the Company's operation are subject to extensive and rapidly changing federal and state environmental regulations governing air emissions, waste water discharges, and solid and hazardous waste management activities. Therefore it is extremely difficult to reasonably quantify future environmental related expenditures.

QOG was involved in a lawsuit with Devon SFS Operating, Inc. (Case #01-C-58C, Neosho County, Kansas) regarding the validity of its natural gas and oil lease on a 160-acre parcel referred to as the Umbarger Lease. In April 2003, the court granted Devon SFS Operating, Inc.'s Motion for Summary Judgment ruling that QOG's lease to the property was not valid. QOG has not drilled a well on the property and the loss of the lease will not have a material adverse effect on the Company's results of operations or financial condition.

The Company and STP have been named defendants in a lawsuit (Case #CJ-2003-30) filed by Plaintiffs Eddie R. Hill et al on March 27, 2003 in the District Court for Craig County, Oklahoma. Plaintiffs are royalty owners who are alleging underpayment of royalties owed them by STP and the Company. The plaintiffs also allege, among other things, that STP and the Company have engaged in self-dealing, have breached their fiduciary duties to the plaintiffs and have acted fraudulently towards the plaintiffs. The plaintiffs are seeking unspecified actual and punitive damages as a result of the alleged conduct by STP and the Company. Based on the information available to date and a preliminary investigation, the Company believes that the claims against it are without merit and intends to defend against them vigorously.

STP has been named as defendant in a lawsuit (Case #CJ-2003-137) filed by Plaintiff Davis Operating Company on October 14, 2003 in the District Court of Craig County, Oklahoma. Plaintiff is alleging improper operation of a natural gas gathering system. The plaintiff is seeking unspecified actual and punitive damages as a result of the alleged improper operations by STP. Discovery is ongoing and the case is scheduled for trial in September 2004. Based on the information available to date and a preliminary investigation, the Company believes that the claims are without merit and intends to defend against them vigorously.

The Company, from time to time, may be subject to legal proceedings and claims that arise in the ordinary course of its business. Although no assurance can be given, management believes, based on its experiences to date, that the ultimate resolution of such items will not have a material adverse impact on the Company's business, financial position or results of operations.

10. Earnings Per Share

SFAS 128 requires a reconciliation of the numerator and denominator of the basic and diluted earnings per share (EPS) computations. The following securities were not included in the calculation of diluted earnings per share because their effect was anti-dilutive.

- For the years ended May 31, 2004 and 2003, dilutive shares do not include outstanding warrants to purchase 1,600,000 and 898,000 shares, respectively, of common stock at an exercise price of $.001 because the effects were antidilutive.
- For the years ended May 31, 2004 and 2003, dilutive shares do not include the assumed conversion of the outstanding 10% preferred stock (convertible into 40,000 common shares) because the effects were antidilutive.
- For the years ended May 31, 2004 and 2003, dilutive shares do not include the assumed conversion of convertible debt (convertible into 20,000 common shares in fiscal 2004 and 163,000 common shares in fiscal 2003) because the effects were antidilutive.

The following reconciles the components of the EPS computation:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
For the year ended May 31, 2004:			
Income (loss) before cumulative effect of accounting change, net of tax	$ (365,000)		
Preferred stock dividends	(10,000)		
Basic EPS income (loss) available to common shareholders before cumulative effect of accounting change, net of tax	$ (375,000)	13,970,880	$ (0.03)
Effect of dilutive securities:			
None	--	--	--
Diluted EPS income available to common shareholders	$ (375,000)	13,970,880	$ (0.03)

	Income (Numerator)	Shares (Denominator)	Per Share Amount
For the year ended May 31, 2003:			
Net loss	$ (3,563,000)		
Preferred stock dividends	(10,000)		
Basic EPS income available to common shareholders	$ (3,573,000)	10,236,288	$ (0.35)
Effect of dilutive securities:			
None	--	--	--
Diluted EPS income available to common shareholders	$ (3,573,000)	10,236,288	$ (0.35)

11. Asset Retirement Obligation

As described in Note 1, effective June 1, 2003, the Company adopted SFAS 143, *Accounting for Asset Retirement Obligations*. Upon adoption of SFAS 143, the Company recorded a cumulative effect to net income of ($28,000) net of tax, or ($.00) per share. Additionally, the Company recorded an asset retirement obligation liability of $254,000 and an increase to net properties and equipment of $207,000.

The following table provides a roll forward of the asset retirement obligations for the year ended May 31, 2004.

	Year Ended May 31, 2004
Asset retirement obligation beginning balance	$ 254,000
Liabilities incurred	457,000
Liabilities settled	(6,000)
Accretion expense	12,000
Revisions in estimated cash flows	--
Asset retirement obligation ending balance	$ 717,000

12. Stock Options

On October 15, 2001, the Company granted stock options in the amount of 400,000 shares of its common stock to two of its directors and an individual that has provided certain consulting services to the Company. The options were fully vested upon grant, had an exercise price of $1.00 per share and an expiration date of December 31, 2003. All stock options were exercised in May 2003.

SFAS 123, *Accounting for Stock-Based Compensation*, requires the Company to provide pro forma information regarding net income per share as if compensation cost for the Company's options had been determined in accordance with the fair value based method prescribed in SFAS 123. Under SFAS 123, the value of each option granted during 2002 was estimated on the date of grant using the Black Scholes model with the following assumptions: risk-free interest rate – 3.1%, dividend yield – 0%, volatility – 177.3% and expected life of the option – 2 to 3 years.

A summary of the status of the Company's non-plan options as of May 31, 2003, and changes during the year ended on those dates is presented below.

	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	400,000	$ 1.00
Granted	--	--
Exercised	(400,000)	1.00
Forfeited	--	--
Outstanding at the end of year	--	$ --

13. Company Benefit Plan

The Company has adopted a 401(K) profit sharing plan with an effective date of June 1, 2001. The plan covers all eligible employees. During the fiscal year ended May 31, 2004, there were no employee contributions to the plan, but the Company contributed 80,888 shares of its common stock to the plan. The Company valued the 2004 common stock contribution at $121,000 and included this amount as an expense in the statement of operations. During the fiscal year ended May 31, 2003, $28,000 was contributed to the plan by employees and $19,000 in matching funds was paid into the plan by the Company. There is a graduated vesting schedule with the employee becoming fully vested after six years of service.

14. Operating Leases

The Company leases natural gas compressors. Terms of these leases call for a minimum obligation of six months and are month to month thereafter. As of May 31, 2004, and 2003, the Company's monthly obligation under these leases totaled $284,000 and $127,000, respectively.

15. Major Purchasers

The Company's natural gas and oil production is sold under contracts with various purchasers. Natural gas sales to one purchaser approximated 90% of total natural gas and oil revenues for the period ended May 31, 2004 and 2003.

16. Financial Instruments

The following information is provided regarding the estimated fair value of the financial instruments, including derivative assets and liabilities as defined by SFAS 133 that the Company held as of May 31, 2004 and the methods and assumptions used to estimate their fair value:

	May 31, 2004	
	Carrying Amount	Fair Value
Derivative liabilities:		
Fixed-price natural gas swaps	$ (18,144,000)	$ (18,144,000)
Fixed-price natural gas collars	$ (1,644,000)	$ (1,644,000)
Bank debt	$ (103,700,000)	$ (103,700,000)
Subordinated debt (inclusive of accrued interest)	$ (54,459,000)	$ (54,459,000)
Other financing agreements	$ (1,377,000)	$ (1,377,000)

The carrying amount of cash, receivables, deposits, accounts payable and accrued expenses approximates fair value due to the short maturity of those instruments. The carrying amounts for convertible debentures and notes payable approximate fair value because the interest rates have remained generally unchanged since the issuance of the convertible debentures and due to the variable nature of the interest rates of the notes payable.

The fair value of fixed-price contracts as of May 31, 2004 was estimated based on market prices of natural gas for the periods covered by the contracts. The net differential between the prices in each contract and market prices for future periods, as adjusted for estimated basis, has been applied to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on a contract-by-contract basis at rates based upon the current market for interest rates. The fair value of derivative instruments that contain options (such as collar structures) has been estimated based on remaining term, volatility and other factors. See Note 17 - Derivatives.

Derivative liabilities reflected as current in the May 31, 2004 balance sheet represent the estimated fair value of fixed-price contract settlements scheduled to occur over the subsequent twelve-month period based on market prices for natural gas as of the balance sheet date. The offsetting increase in value of the hedged future production has not been accrued in the accompanying balance sheet, creating the appearance of a working capital deficit from these contracts. The contract settlement amounts are not due and payable until the monthly period that the related underlying hedged transaction occurs. In some cases the recorded liability for certain contracts significantly exceeds the total settlement amounts that would be paid to a counterparty based on prices in effect at the balance sheet date due to option time value. Since the Company expects to hold these contracts to maturity, this time value component has no direct relationship to actual future contract settlements and consequently does not represent a liability that will be settled in cash or realized in any way.

17. Derivatives

Description of Contracts. The Company seeks to reduce its exposure to unfavorable changes in natural gas prices, which are subject to significant and often volatile fluctuation, through the use of fixed-price contracts. The fixed-price contracts are comprised of energy swaps and collars. These contracts allow the Company to predict with greater certainty the effective natural gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production. Collar structures provide for participation in price increases and decreases to the extent of the ceiling prices and floors provided in those contracts. For the years ended May 31, 2004 and 2003, fixed-price contracts hedged approximately 83.0% and 59.0%, respectively, of the Company's natural gas production. As of May 31, 2004 fixed-price contracts are in place to hedge 16.6 Bcf of estimated future natural gas production. Of this total volume, 7.1 Bcf are hedged for fiscal 2005 and 9.5 Bcf thereafter.

For energy swap contracts, the Company receives a fixed price for the respective commodity and pays a floating market price, as defined in each contract (generally NYMEX futures prices or a regional spot market index), to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty. Natural gas collars contain a fixed floor price (put) and ceiling price (call). If the market price of natural gas exceeds the call strike price or falls below the put strike price, then the Company receives the fixed price and pays the market price. If the market price of natural gas is between the call and the put strike price, then no payments are due from either party.

The following table summarizes the estimated volumes, fixed prices, fixed-price sales and fair value attributable to the fixed-price contracts as of May 31, 2004. See "Market Risk."

	Years Ending May 31,			
	2005	2006	2007	Total
	(dollars in thousands, except price data)			
Natural Gas Swaps:				
Contract vols (MMBtu)	5,741,000	5,633,000	3,292,000	14,666,000
Weighted-avg fixed price per MMBtu (1)	$ 4.96	$ 4.62	$ 4.53	$ 4.73
Fixed-price sales	$ 28,468	$ 26,030	$ 14,912	$ 69,410
Fair value liability (2)	$ (8,779)	$ (7,010)	$ (2,355)	$ (18,144)
Natural Gas Collars:				
Contract vols (MMBtu):				
Floor	1,307,000	612,000	--	1,919,000
Ceiling	1,307,000	612,000	--	1,919,000
Weighted-avg fixed price per MMBtu (1):				
Floor	$ 4.22	$ 4.25	$ --	$ 4.23
Ceiling	$ 5.38	$ 5.30	$ --	$ 5.36
Fixed-price sales (3)	$ 7,034	$ 3,244	$ --	$ 10,278
Fair value liability (2)	$ (1,308)	$ (336)	$ --	$ (1,644)
Total Natural Gas Contracts:				
Contract vols (MMBtu)	7,048,000	6,245,000	3,292,000	16,585,000
Weighted-avg fixed price per MMBtu (1)	$ 5.04	$ 4.69	$ 4.53	$ 4.80
Fixed-price sales (3)	$ 35,502	$ 29,274	$ 14,912	$ 79,688
Fair value liability (2)	$ (10,087)	$ (7,346)	$ (2,355)	$ (19,788)

(1) The prices to be realized for hedged production are expected to vary from the prices shown due to basis. See "Market Risk."

(2) Bracketed amounts are reflected as derivative liabilities on the balance sheet. See Note 16-Financial Instruments.

(3) Assumes ceiling prices for natural gas collar volumes.

The estimates of fair value of the fixed-price contracts are computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date, as adjusted for basis. Forward market prices for natural gas are dependent upon supply and demand factors in such forward market and are subject to significant volatility. The fair value estimates shown above are subject to change as forward market prices and basis change. See Note 16 – Financial Instruments.

Accounting. All fixed-price contracts have been executed in connection with the Company's natural gas hedging program. The differential between the fixed price and the floating price for each contract settlement period multiplied by the associated contract volume is the contract profit or loss. For fixed-price contracts qualifying as cash flow hedges pursuant to SFAS 133, the realized contract profit or loss is included in natural gas and oil sales in the period for which the underlying production was hedged. For the years ended May 31, 2004 and 2003, natural gas and oil sales included $649,000 and $0, respectively of net losses associated with realized gains and losses under fixed-price contracts.

For contracts that did not qualify as cash flow hedges, the realized contract profit and loss is included in other revenue and expense in the period for which the underlying production was hedged. For the years ended May 31, 2004 and 2003, other revenue and expense included $1.5 million and $1.2 million, respectively, of net losses associated with realized gains and losses under fixed-price contracts.

For fixed-price contracts qualifying as cash flow hedges, changes in fair value for volumes not yet settled are shown as adjustments to other comprehensive income. For those contracts not qualifying as cash flow hedges, changes in fair value for volumes not yet settled are recognized in change in derivative fair value in the statement of operations. The fair value of all fixed-price contracts are recorded as assets or liabilities in the balance sheet.

Change in derivative fair value in the statements of operations for the years ended May 31, 2004 and 2003 is comprised of the following:

	Year Ended May 31, 2004	Year Ended May 31, 2003
Change in fair value of derivatives not qualifying as cash flow hedges	$ (1,740,000)	$ (4,867,000)
Amortization of derivative fair value gains and losses recognized in earnings prior to actual cash settlements	888,000	--
Ineffective portion of derivatives qualifying as cash flow hedges	(1,161,000)	--
	$ (2,013,000)	$ (4,867,000)

The amounts recorded in change in derivative fair value do not represent cash gains or losses. Rather, they are temporary valuation swings in the fair value of the contracts. All amounts initially recorded in this caption are ultimately reversed within this same caption over the respective contract terms.

In addition to the future net settlements identified in the above table under "—Description of Contracts", the Company expects that change in derivative fair value in the statement of operations will include a gain of $10.1 million in fiscal 2005 relating to the unwinding of previously recognized net losses in this caption as actual contract cash settlements are realized.

Credit Risk. Energy swaps and collars provide for a net settlement due to or from the respective party as discussed previously. The counterparty to the fixed-priced contracts is a financial institution. Should the counterparty default on a contract, there can be no assurance that the Company would be able to enter into a new contract with a third party on terms comparable to the original contract. The Company has not experienced non-performance by its counterparty.

Cancellation or termination of a fixed-price contract would subject a greater portion of the Company's natural gas production to market prices, which, in a low price environment, could have an adverse effect on its future operating results. In addition, the associated carrying value of the contract would be removed from the balance sheet.

Market Risk. The differential between the floating price paid under each energy swap contract and the price received at the wellhead for the Company's production is termed "basis" and is the result of differences in location, quality, contract terms, timing and other variables. The effective price realizations that result from the fixed-price contracts are affected by movements in basis. Basis movements can result from a number of variables, including regional supply and demand factors, changes in the portfolio of the Company's fixed-price contracts and the composition of its producing property base. Basis movements are generally considerably less than the price movements affecting the underlying commodity, but their effect can be significant.

Changes in future gains and losses to be realized in natural gas and oil sales upon cash settlements of fixed-price contracts as a result of changes in market prices for natural gas are expected to be offset by changes in the price received for hedged natural gas production.

18. SFAS 69 SUPPLEMENTAL DISCLOSURES (UNAUDITED)

Net Capitalized Costs

The Company's aggregate capitalized costs related to natural gas and oil producing activities are summarized as follows:

	May 31, 2004
Natural gas and oil properties and related lease equipment:	
Proved	$ 123,161,000
Unproved	24,662,000
	147,823,000
Accumulated depreciation and depletion	(8,881,000)
Net capitalized costs	$ 138,942,000

Unproved properties not subject to amortization consisted mainly of leasehold acquired through acquisitions. We will continue to evaluate our unproved properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

Costs Incurred

Costs incurred in natural gas and oil property acquisition, exploration and development activities which have been capitalized are summarized as follows:

	Years Ended May 31,	
	2004	2003
Acquisition of properties proved and unproved	$ 115,069,000	$ 9,716,000
Development costs	11,621,000	7,430,000
	$ 126,690,000	$ 17,146,000

Results of Operations for Natural Gas and Oil Producing Activities

The Company's results of operations from natural gas and oil producing activities are presented below for 2004 and 2003. The following table includes revenues and expenses associated directly with our natural gas and oil producing activities. It does not include any interest costs and general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our natural gas and oil operations.

	Years Ended May 31,	
	2004	2003
Production revenues	$ 28,147,000	$ 8,345,000
Production costs	(6,835,000)	(1,923,000)
Depreciation and depletion	(6,802,000)	(1,612,000)
	14,510,000	4,810,000
Imputed income tax provision (1)	(5,804,000)	(1,924,000)
Results of operation for natural gas & oil producing activity	$ 8,706,000	$ 2,886,000

(1) The imputed income tax provision is hypothetical (at the statutory rate) and determined without regard to our deduction for general and administrative expenses, interest costs and other income tax credits and deductions, nor whether the hypothetical tax provision will be payable.

Natural Gas and Oil Reserve Quantities

The following schedule contains estimates of proved natural gas and oil reserves attributable to the Company. Proved reserves are estimated quantities of natural gas and oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those which are expected to be recovered through existing wells with existing equipment and operating methods. Reserves are stated in thousand cubic feet (mcf) of natural gas and barrels (bbl) of oil. Geological and engineering estimates of proved natural gas and oil reserves at one point in time are highly interpretive, inherently imprecise and subject to ongoing revisions that may be substantial in amount. Although every reasonable effort is made to ensure that the reserve estimates are accurate, may be their nature reserve estimates are generally less precise that other estimates presented in connection with financial statement disclosures.

	Gas - mcf	Oil - bbls
Proved reserves:		
Balance, May 31, 2002	14,869,970	223,206
Purchase of reserves-in-place	12,568,000	--
Extensions and discoveries	2,321,343	--
Revisions of previous estimates	--	(166,000)
Production	(1,488,679)	(14,123)
Balance, May 31, 2003	28,270,634	43,083
Purchase of reserves-in-place	99,700,000	--
Extensions and discoveries	11,219,900	22,571
Revisions of previous estimates	(84,126)	--
Production	(5,530,208)	(8,549)
Balance, May 31, 2004	133,576,200	57,105
Proved developed reserves:		
Balance, May 31, 2003	14,016,064	43,083
Balance, May 31, 2004	62,558,900	57,105

Standardized Measure of Discounted Future Net Cash Flows:

The following schedule presents the standardized measure of estimated discounted future net cash flows from the Company's proved reserves for the years ended May 31, 2004 and 2003. Estimated future cash flows are based on independent reserve data. Because the standardized measure of future net cash flows was prepared using the prevailing economic conditions existing at May 31, 2004 and 2003, it should be emphasized that such conditions continually change. Accordingly, such information should not serve as a basis in making any judgment on the potential value of the Company's recoverable reserves or in estimating future results of operations.

	May 31,	
	2004	2003
Future production revenues (1)	$ 796,329,000	$ 136,820,000
Future production costs	(264,810,000)	(34,975,000)
Future development costs	(48,773,000)	(6,273,000)
Future cash flows before income taxes	482,746,000	95,572,000
Future income tax	(128,000,000)	(31,267,000)
Future net cash flows	354,746,000	64,305,000
Effect of discounting future annual net cash flows at 10%	(69,998,000)	(17,237,000)
Standardized measure of discounted net cash flows	$ 284,748,000	$ 47,068,000

(1) The weighted average natural gas and oil wellhead prices used in computing our reserves were $5.95 per mcf and $35.25 per bbl at May 31, 2004, compared to $4.80 per mcf and $27.00 per bbl at May 31, 2003.

The principal changes in the standardized measure of discounted future net cash flows relating to proven natural gas and oil properties were as follows:

	Fiscal Years Ended May 31,	
	2004	2003
Sales and transfers of natural gas and oil, net of production costs	$ (21,312,000)	$ (6,422,000)
Net changes in prices and production costs	11,313,000	22,984,000
Acquisitions of natural gas and oil in place – less related production costs	330,454,000	36,106,000
Extensions and discoveries, less related production costs	37,189,000	6,675,000
Revisions of previous quantity estimates less related production costs	2,852,000	(3,717,000)
Accretion of discount	3,917,000	2,555,000
Net change in income taxes	(126,733,000)	(22,780,000)
Total change in standardized measure of discounted future net cash flows	$ 237,680,000	$ 35,401,000

The following schedule contains a comparison of the standardized measure of discounted future net cash flows to the net carrying value of proved natural gas and oil properties at May 31, 2004 and 2003:

	2004	2003
Standardized measure of discounted future net cash flows	$ 284,748,000	$ 47,068,000
Proved natural gas & oil property net of accumulated depletion	114,280,000	16,694,000
Standardized measure of discounted future net cash flows in excess of net carrying value of proved natural gas and oil properties	$ 170,468,000	$ 30,374,000

19. Recent Accounting Pronouncements

Accounting for Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS 143 is effective for fiscal years beginning after June 15, 2002 and establishes an accounting standard requiring the recording of the fair value of liabilities associated with the retirement of long-term assets (mainly plugging and abandonment costs for depleted wells) in the period in which the liability is incurred (at the time the wells are drilled). Accordingly, we adopted this standard on June 1, 2003. Upon adoption of SFAS 143, the Company recorded a cumulative effect to net income of ($28,000) net of tax, or ($.00) per share. Additionally, the Company recorded an asset retirement obligation liability of $254,000 and an increase to net properties and equipment of $207,000.

Accounting for the Impairment or Disposal of Long-Lived Assets

In August 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, which supersedes SFAS Statement No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of.* This new statement also supersedes certain aspects of the Accounting Principles Board Opinion (APB) No. 30, *Reporting the Results of Operations - Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions*, with regard to reporting the effects of a disposal of a segment of a business and will require expected future operating losses from discontinued operations to be reported in discontinued operations in the period incurred (rather than estimated as of the measurement date as was required by APB No. 30). The financial statements are unaffected by implementation of this new standard.

Rescission of FASB Statements No. 44, and No. 64, Amendment of FASB Statement No. 13, and Technical Corrections

In April 2002, the FASB issued Statement of Financial Accounting Standard No. 145, *Rescission of FASB Statements No. 44, and No. 64, Amendment of FASB Statement No. 13, and Technical Corrections*, which updates, clarifies and simplifies existing accounting pronouncements. SFAS No. 4, which required all gains and losses from the extinguishment of debt to be aggregated and , if material, classified as an extraordinary item, net of related tax effect was rescinded, as a result, SFAS 64, which amended SFAS No. 4, was rescinded as it was no longer necessary. SFAS No. 145 amended SFAS No. 13 to eliminate an inconsistency between the required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. As of May 31, 2004, the Company had not incurred any transactions of the type addressed in this FASB.

Acquisition of Certain Financial Institutions

In October 2002, the Financial Accounting Standards Board issued SFAS No. 147, *Acquisition of Certain Financial Institutions* . As of May 31, 2004, this statement has no effect on the Company's reporting as it has not acquired any financial institutions.

Accounting for Stock-Based Compensation- Transition and Disclosure

In December 2002, the Financial Accounting Standards Board issued SFAS No. 148, *Accounting for Stock-Based Compensation- Transition and Disclosure*. This statement amends SFAS No. 123, *Accounting for Stock Based Compensation*, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. The Company has adopted the disclosure requirements of SFAS 148.

Amendment of Statement 133 on Derivative Instruments and Hedging Activities

In April 2003, the Financial Accounting Standards Board issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging actives under FASB No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS 149 is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of SFAS 149 did not materially impact the earnings and financial position of the Company.

Accounting for Certain Financial Instruments with Characteristics of both Liability and Equity

In May 2003, the Financial Accounting Standards Board issued SFAS No. 150 *Accounting for Certain Financial Instruments with Characteristics of both Liability and Equity*. This standard establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. We do not expect this statement to have an effect on our reporting as the Company has no financial instruments with these characteristics.

20. Subsequent Events

On July 22, 2004, Quest Cherokee entered into a new syndicated credit facility arranged and syndicated by UBS Securities LLC, with UBS AG, Stamford Branch as agent (the "UBS Credit Agreement"). The UBS Credit Agreement provides for a $120 million six year term loan that was fully funded at closing (the "UBS Term Loan") and a $20 million five year revolving credit facility that can be used to issue letters of credit and fund future working capital needs and general corporate purposes (the "UBS Revolving Loan"). The UBS Credit Agreement also contains a $15 million "synthetic" letter of credit facility that matures in December 2008 in order to provide credit support for Quest Cherokee's natural gas hedging program. A portion of the proceeds from the UBS Term Loan were used to repay the Bank One credit facilities. After the repayment of the Bank One credit facilities and payment of fees and other obligations related to this transaction, Quest Cherokee had approximately $9 million of cash at closing from the proceeds of the UBS Term Loan and $15 million of availability under the UBS Revolving Loan.

Interest accrues under both the UBS Term Loan and the UBS Revolving Loan, at Quest Cherokee's option, at either (i) a rate equal to the greater of the corporate "base rate" established by UBS AG, Stamford Branch, or the federal funds effective rate plus 0.50% (the "Alternative Base Rate"), plus the applicable margin (2.75% for revolving loans and 3.00% for term loans), or (ii) LIBOR, as adjusted to reflect the maximum rate at which any reserves are required to be maintained against Eurodollar liabilities (the "Adjusted LIBOR Rate"), plus the applicable margin (3.75% for revolving loans and 4.00% for term loans). In the event of a default under either the UBS Term Loan or the UBS Revolving Loan, interest will accrue at the applicable rate, plus an additional 2% per annum. Quest Cherokee pays an annual fee on the synthetic letter of credit facility equal to 4.00% of the amount of the facility.

The UBS Credit Agreement may be repaid at any time without any premium or prepayment penalty. An amount equal to $300,000 (0.25% of the original principal balance of the UBS Term Loan) is required to be repaid each quarter, commencing December 31, 2004. In addition, Quest Cherokee is required to semi-annually apply 50% of Excess Cash Flow (or 25% of Excess Cash Flow, if the ratio of the present value (discounted at 10%) of the future cash flows from Quest Cherokee's proved mineral interest to Total Net Debt is greater than or equal to 2.25:1.0) to repay the UBS Term Loan. "Excess Cash Flow" for any semi-annual period is generally defined as net cash flow from operations for that period less (1) principal payments of the UBS Term Loan made during the period, (2) the lower of actual capital expenditures or budgeted capital expenditures during the period and (3) permitted tax distributions made during the period or that will be paid within six months after the period. "Total Net Debt" is generally defined as funded indebtedness less up to $10 million of unrestricted cash.

The UBS Credit Agreement is secured by a lien on the substantially all of the assets of Quest Cherokee (other than the pipeline assets owned by Bluestem) and a pledge of the membership interest in Bluestem. Bluestem also guaranteed Quest Cherokee's obligations under the UBS Credit Agreement.

The UBS Credit Agreement contains affirmative and negative covenants that are typical for credit agreements of this type. The covenants in the UBS Credit Agreement include provisions requiring the maintenance of and furnishing of financial and other information; the maintenance of insurance, the payment of taxes and compliance with the law; the maintenance of collateral and security interests and the creation of additional collateral and security interests; the maintenance of certain financial ratios; restrictions on the incurrence of additional debt or the issuance of convertible or redeemable equity securities; restrictions on the granting of liens; restrictions on making acquisitions and other investments; restrictions on disposing of assets and merging or consolidating with a third party where Quest Cherokee is not the surviving entity; restrictions on the payment of dividends and the repayment of other indebtedness; restrictions on transactions with affiliates that are not on an arms length basis; and restrictions on changing the nature of Quest Cherokee's business.

Under the UBS Credit Agreement, no payments may be made on the ArcLight subordinated promissory note nor may any distributions be made to the members of Quest Cherokee until after the November 30, 2004 reserve report has been delivered to the lenders. After that date, payments may be made with respect to the subordinated promissory note and distributions made to the members of Quest Cherokee semi-annually, but only if all of the following conditions have been met:

- no default exists on the date any such payment is made, and no default or event of default would result from the payment, under the UBS Credit Agreement.

- for the most recent four consecutive quarters, the ratio of the present value (discounted at 10%) of the future cash flows from Quest Cherokee's proved mineral interest to Total Net Debt is at least 1.75:1.0 and the ratio of Total Net

Debt to Consolidated EBITDA does not exceed 3.00:1.0, in each case, after giving effect to such payment. "Consolidated EBITDA" is generally defined as consolidated net income, plus interest expense, amortization, depreciation, taxes and non-cash items deducted in computing consolidated net income and minus non-cash items added in computing consolidated net income.

- the amount of such semi-annual payments do not exceed Quest Cherokee's Excess Cash Flow during the preceding half of the fiscal year less (1) the amount of Excess Cash Flow required to be applied to repay the UBS Term Loan, and (2) any portion of the Excess Cash Flow that is used to fund capital expenditures.

- The UBS Credit Agreement provides that it is an event of default if a "change of control" occurs. A "change of control" is defined to include Bluestem, or any other wholly owned subsidiary of Quest Cherokee no longer being wholly owned by Quest Cherokee; ArcLight and the Company collectively ceasing to own at least 51% of the equity interests and voting stock of Quest Cherokee; or Mr. Cash ceasing to be an executive officer of Quest Cherokee, unless a successor reasonably acceptable to UBS AG, Stamford Branch is appointed within 60 days.

In connection with the UBS Credit Agreement, the maturity date of the subordinated promissory note issued to ArcLight was extended to the later of October 22, 2010 and the maturity date of the UBS Term Loan, subject to extension until December 22, 2010.

No other material subsequent events have occurred that warrants disclosure since the balance sheet date.

ITEM 8. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

NONE.

ITEM 8A. CONTROLS AND PROCEDURES

The following information reflects the restatement of the Company's financial statements as discussed in Note 2 of the Notes to Consolidated Financial Statements included in Part I, Item 1 of this Form 10-KSB.

(a) Evaluation of disclosure controls and procedures.

The Company's management, including the Co-Chief Executive Officers and the Chief Financial Officer, evaluated the Company's disclosure controls and procedures. Based on that evaluation, the Co-Chief Executive Officers and the Chief Financial Officer concluded that, except as noted below with respect to the identification and correction of certain accounting errors, the Company's disclosure controls and procedures are effective in all material respects to provide reasonable assurance that information required to be disclosed in the reports that the Company files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

(b) Changes in internal controls.

During the period covered by this report, the Company identified various accounting errors in its financial reports. The Company has restated its financial results for fiscal year 2003 and the first quarter of fiscal year 2004 to reflect adjustments necessary to correct these accounting errors. The adjustments primarily relate to the failure to adopt and properly apply the accounting pronouncements described in Note 2 of the Notes to Consolidated Financial Statements included in Part I, Item 7 of this Form 10-KSB.

In response to its discovery of these accounting errors, the Company enhanced its internal control over financial reporting so that it has the appropriate resources to implement new accounting standards and apply existing accounting standards to new transactions. As described in the Company's Form 10-KSB/A (Amendment No. 2), for the fiscal year ended May 31, 2003, filed with the SEC on September 10, 2004, the steps taken by the Company include:

1. Hiring a new chief financial officer with significant public company corporate finance and accounting experience, a controller and other personnel to increase the depth and experience of the Company's finance and accounting staff;

2. Centralizing the accounting functions in the Company's Oklahoma City corporate headquarters;

3. Investing in new accounting and management information systems to support the Company's timely reconciliation and review of accounts and disclosures and the timely filing of financial reports with the Securities and Exchange Commission;

4. Reviewing accounting literature and other technical materials with the Company's auditor to ensure that the appropriate personnel have a full awareness and understanding of the applicable accounting pronouncements and how they are to be implemented;

5. Improving the documentation of the Company's accounting policies and procedures at the time of adoption; and

6. Improving the documentation of the Company's internal control procedures.

It should be noted, however, that no matter how well designed and operated, a control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events. Because of these and other inherent limitations of control systems (including faulty judgments in decision making or breakdowns resulting from simple errors or mistakes), there can be no assurance that any design will succeed in achieving its stated goals under all potential conditions. Additionally, controls can be circumvented by individual acts, collusion or by management override of the controls in place.

ITEM 8B. OTHER INFORMATION.

NONE.

PART III

ITEM 9. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

The information required by this Item is incorporated herein by reference from the Company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's fiscal year ended May 31, 2004.

ITEM 10. EXECUTIVE COMPENSATION.

The information required by this Item is incorporated herein by reference from the Company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's fiscal year ended May 31, 2004.

ITEM 11. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this Item is incorporated herein by reference from the Company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's fiscal year ended May 31, 2004.

ITEM 12. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is incorporated herein by reference from the Company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's fiscal year ended May 31, 2004.

ITEM 13. EXHIBITS

Index to Exhibits. Exhibits required to be attached by Item 601 of Regulation S-B are listed in the Index to Exhibits beginning on page 25 of this Form 10-KSB, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated herein by reference from the Company's definitive Proxy Statement for its 2004 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's fiscal year ended May 31, 2004.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this annual report on Form 10-KSB to be signed on its behalf by the undersigned, thereunto duly authorized this 20th day of September, 2004.

Quest Resource Corporation

/s/ Douglas L. Lamb
Douglas L. Lamb, President

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

Signature	Title	Date
/s/ Jerry D. Cash Jerry D. Cash	Chairman/Director (Co-Chief Executive Officer)	September 20, 2004
/s/ Douglas L. Lamb Douglas L. Lamb	President/Director (Co-Chief Executive Officer)	September 20, 2004
/s/ David E. Grose David E. Grose	Principal Financial and Accounting Officer	September 20, 2004
/s/ John C. Garrison John C. Garrison	Director	September 20, 2004
/s/ James B. Kite, Jr. James B. Kite, Jr.	Director	September 20, 2004

CORPORATE DIRECTORY

DIRECTORS

Jerry D. Cash
Chairman of the Board and
Chief Executive Officer
Quest Resource Corporation

John C. Garrison
Private Investor

James B. Kite, Jr.
Private Investor

Douglas L.Lamb
President and
Chief Operating Officer
Quest Resource Corporation

This Fiscal 2004 Annual Report on Form 10-KSB includes the financial statements but excludes pages of routine exhibits contained in the Form 10-KSB filed with the Securities and Exchange Commission. We will furnish the excluded exhibits to you upon request.

David E. Grose
Secretary

OFFICERS

Jerry D. Cash
Chairman of the Board and
Chief Executive Officer

Douglas L.Lamb
President and
Chief Operating Officer

David E. Grose
Chief Financial Officer and
Secretary

GENERAL CORPORATE DATA

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Auditors
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Oklahoma City, Oklahoma

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Stock Transfer Agent
Securities Transfer Corporation
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Corporate Headquarters
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Oklahoma City, Oklahoma 73120

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