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1-17371

QUEST RESOURCE CORPORATION

[redacted]

QUEST
Resource Corporation

Annual Report

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

FORM 10-KSB/A
(Amendment No. 1)

(Mark One)

[ ] Annual report under Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended ____________________.

[X] Transition report under Section 13 or 15(d) of the Securities Exchange Act of 1934 (no fee required) for the transition period from June 1, 2004 to December 31, 2004.

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 transition period ended December 31, 2004 were $26,156,000. 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 April 6, 2005 at $4.00 per share was $22,119,860. This figure assumes that only the directors and officers of the Company, their spouses and controlled corporations were affiliates.

There were 14,249,694 shares outstanding of the issuer's common stock as of April 6, 2005.

DOCUMENTS INCORPORATED BY REFERENCE

The definitive proxy statement relating to the issuer's 2005 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 1,000 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.

The Company elected to change its year end from May 31 to December 31. Accordingly, the Company's financial statements have been prepared for the seven months ended December 31, 2004, and now will be prepared for a calendar year going forward. In view of this change, this Form 10-KSB is a transition report and includes financial information for the seven-month transition period ended December 31, 2004 and for the twelve-month periods ended May 31, 2004 and 2003.

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 still remains 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
- reviewing other basins for coal bed methane opportunities.

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

- low overhead costs,
- cost efficient operations,
- large 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 coal bed methane natural gas.

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. Initially, the Company consolidated all of its employees into QES. Quest Cherokee Oilfield Services, LLC ("QCOS") was formed in September 2004 as a subsidiary of Quest Cherokee to acquire the stimulation assets from Consolidated Oil Well Services. At that time, the Company's vehicles, equipment, field employees and first level supervisors were transferred to QCOS. The costs associated with field employees, first level supervisors, exploration, development and operation of the Company's properties and certain other direct charges are now borne by QCOS. QES continues to employ all of the Company's non-field employees. 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 is currently reviewing the management fee to determine if it will be sufficient to cover such expenses for the foreseeable future.

After giving effect to the restructuring, STP continued 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. The acquisition closed 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. 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, $2.6 million in May 2004 and $0.6 million in September, 2004. See the 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 15% junior subordinated promissory note (the "Original Note") to Cherokee Energy Partners LLC, a wholly-owned subsidiary of Cherokee Energy Partners Fund I, L.P. ("ArcLight"), pursuant to the terms of a note purchase agreement dated as of December 22, 2003 between Quest Cherokee and ArcLight. In connection with the purchase of the Original 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. See the Company's Form 8-K filed on January 6, 2004 for additional information regarding the terms of ArcLight's investment in Quest Cherokee.

Although management of the Company is responsible for the day-to-day operations of Quest Cherokee, Quest Cherokee's board of managers must approve all major decisions regarding Quest Cherokee. 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.

On February 11, 2005, Quest Cherokee and ArcLight amended and restated the note purchase agreement to provide for the issuance to ArcLight of up to $15 million of additional 15% junior subordinated promissory notes (the "Additional Notes" and together with the Original Notes, the "Subordinated Notes") pursuant to the terms of an amended and restated note purchase agreement. Also on February 11, 2005, Quest Cherokee issued $5 million of Additional Notes to ArcLight (the "Second Issuance"). As a condition to the Second Issuance, the following changes were made to the terms of ArcLight's original investment in Quest Cherokee:

(i) the make-whole payment due to ArcLight in the event that Quest Cherokee is dissolved was changed from (a) the difference between the amount ArcLight has received on account of principal and interest on the Original Notes and 150% of the original principal amount of the Original Notes, to (b) the difference between the amount ArcLight has received on account of principal and interest on the Subordinated Notes and 140% of the original principal amount of the Subordinated Notes—this change effectively removed any make-whole premium with respect to the Additional Notes in the event of an early liquidation of Quest Cherokee;

(ii) the portion of Quest Cherokee's net cash flow that is required to be used to repay the Subordinated Notes was increased from 85% to 90%, and the portion of the net cash flow distributable to the Company's subsidiaries, as the holders of all of Quest Cherokee's Class B units, was decreased from 15% to 10%, until the Subordinated Notes have been repaid; and

(iii) after the Subordinated Notes have been repaid and ArcLight has received a 30% internal rate of return on its investment in Quest Cherokee, Quest Cherokee's net cash flow will be distributed 35% to ArcLight (as the holder of the Class A Units) and 65% to the Company's subsidiaries (as the holders of the Class B Units); previously such net cash flow would have been distributed 30% to ArcLight and 70% to the Company's subsidiaries.

The amended and restated note purchase agreement also provided for Quest Cherokee to issue to ArcLight Additional Notes in the principal amount of $7 million (the "Third Issuance") upon Quest Cherokee obtaining a waiver from the lenders under its existing UBS Credit Agreement with respect to Quest Cherokee's default under the UBS Credit Agreement and an amendment to the UBS Credit Agreement to permit the issuance of Additional Notes to ArcLight. On February 22, 2005, Quest Cherokee obtained the necessary waivers and amendments to the UBS Credit Agreement and closed on the Third Issuance. At the same time, Quest Cherokee borrowed $5 million of additional term loans under the UBS Credit Agreement.

Finally, the amended and restated note purchase agreement provides Quest Cherokee with the option to issue to ArcLight Additional Notes in the principal amount of $3 million (the "Fourth Issuance"). In the event of the Fourth Issuance:

(i) the interest rate on the Subordinated Notes would increase from 15% to 20%;

(ii) the portion of Quest Cherokee's net cash flow that is required to be used to repay the Subordinated Notes would be further increased from 90% to 95%, and the portion of the net cash flow distributable to the Company's subsidiaries, as the holders of all of Quest Cherokee's Class B units, would be further decreased from 10% to 5%, until the Subordinated Notes have been repaid; and

(iii) after the Subordinated Notes have been repaid and ArcLight has received a 30% internal rate of return on its investment in Quest Cherokee, Quest Cherokee's net cash flow would be distributed 40% to ArcLight (as the holder of the Class A Units) and 60% to the Company's subsidiaries (as the holders of the Class B Units).

It is not currently anticipated that Quest Cherokee will exercise its option to issue any Additional Notes in a Fourth Issuance.

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.

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 and a five year $35 million senior term second lien secured loan arranged and syndicated by Banc One Capital Markets, Inc. and with Bank One, NA, as agent. The senior revolving loan 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.

On July 22, 2004, the Bank One credit facilities were refinanced with a new syndicated credit facility arranged and syndicated by UBS Securities LLC, with UBS AG, Stamford Branch as administrative agent (the "UBS Credit Agreement"). The UBS Credit Agreement originally provided 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 could be used to issue letters of credit and fund future working capital needs and general corporate purposes (the "UBS Revolving Loan"). As of December 31, 2004, Quest Cherokee had approximately $15 million of loans and approximately $5 million in letters of credit issued under the UBS Revolving Loan. Letters of credit issued under the UBS Revolving Loan reduce the amount that can be borrowed thereunder. The UBS Credit Agreement also contains a $15 million "synthetic" letter of credit facility that matures in December 2008, which provides credit support for Quest Cherokee's natural gas hedging program. Subsequent to December 31, 2004 and in connection with the Third Issuance of Subordinated Notes to ArcLight, the UBS Credit Agreement was amended to increase the UBS Term Loan to $125 million. See Item 6. "Management's Discussion and Analysis of Financial Condition or Plan of Operation–Capital Resources and Liquidity–UBS Credit Facility."

Other Recent Acquisitions

Quest Cherokee acquired certain assets from Consolidated Oil Well Services on September 15, 2004 in the amount of $4.1 million. The assets consisted of cementing, acidizing and fracturing equipment and a related office building and storage facility in Chanute, Kansas. The acquisition was funded with a portion of the remaining net proceeds from the $120 million term loan under the UBS Credit Agreement.

Quest Cherokee formed Quest Cherokee Oilfield Service, LLC ("QCOS") to acquire the Consolidated vehicles and equipment and transferred all existing field assets (vehicles and equipment) and field personnel and first level supervisors to QCOS. Under the terms of the UBS Credit Agreement, QCOS was required to become a guarantor of the UBS Credit Agreement and has pledged its assets as security for its guarantee.

The Company acquired approximately 80 miles of an inactive oil pipeline for approximately $1 million on August 10, 2004. The Company intends to convert this former oil pipeline into a natural gas pipeline. The acquisition was funded with a portion of the remaining net proceeds from the $120 million term loan under the new credit facility with UBS. Additionally, the Company acquired 8 non-producing wells and approximately 8,000 acres in the Cherokee Basin on August 6, 2004 for $750,000.

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 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 controlled the operational rights to, approximately 274 miles of natural gas gathering pipelines. J-W also owned a fleet of trucks and well servicing equipment, and a shop building in Howard, Kansas. 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.

Kentucky Lease

On July 18, 2003 the Company entered into a coal bed methane lease with Alcoa Fuels, Inc., a subsidiary of Alcoa Inc. (NYSE: AA), for more than 63,200 net acres in western Kentucky. The Company has determined that it is not feasible to develop the property in western Kentucky and has elected to not renew the lease. Developing this property could have required the Company to obtain significant additional capital resources. Since this property was outside of Quest Cherokee, the assets and financial resources of Quest Cherokee would not be available to support the development of 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 December 31, 2004, the Company controlled approximately 517,000 gross 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 December 31, 2004: estimated gross natural gas proved reserves of 185 Bcf, of which 149.8 Bcf is net to the Company, and estimated net proved oil reserves of 47,834 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 $401.1 million.

As of December 31, 2004, the Company was producing natural gas from approximately 795 wells (gross) at an average per well rate of 43 mcf/d measured at the wellhead. The Company's total daily natural gas sales (including pipeline-earned volume) as of December 31, 2004 were approximately 25,460 mcf/d net (33,875 mcf/d gross).

The Company has a significant amount of acreage available for development. As of December 31, 2004, the Company had leases with respect to 205,230 gross undeveloped acres. For the seven months ended December 31, 2004, the Company drilled approximately 330 wells and had connected 117 wells to its pipeline systems. During the 2005 calendar year, the Company intends to drill approximately 159 wells (subject to compliance with the limitations contained in the UBS Credit Agreement – See Item 6. "Management's Discussion and Analysis or Plan of Operation – Capital Resources and Liquidity – UBS Credit Facility") and intends to drill approximately 1,140 wells over the three year period subsequent to calendar year 2005. The Company has identified approximately 600 proved undeveloped drilling locations and many more probable and possible drilling locations. The Company believes that it has the necessary expertise, manpower and equipment 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 have the funding required to 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 $85,000 historical cost for drilling and completing a well 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 December 31, 2004 and 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.

	PRODUCTIVE WELLS						LEASEHOLD ACREAGE (1)					
As of	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
Dec. 31												
2004	795	774.3	29	27.9	824	802.2	311,941	291,318	205,230	187,884	517,171	479,202

(1) The above leasehold acreage data as of December 31, 2004, excludes leasehold acreage in the State of Kentucky previously included in prior periods, as the Company has decided to not renew these leases. See "Recent Developments – Kentucky Lease".

During the seven months ended December 31, 2004, the Company drilled 330 gross (320 net) new wells on its properties, the majority of which were natural gas wells. The wells drilled have been evaluated and were included in the year-end reserve report. Of the additional wells drilled and evaluated during the transition period, eleven wells were deemed to be temporarily abandoned. The oil well count remains constant as the Company is focusing on adding natural gas reserves. ("See Summary of New and Abandoned Well Activity"). During the seven month transition period ended December 31, 2004, the Company continued to lease additional acreage in certain core development areas of the Cherokee Basin.

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 December 31, 2004 and May 31, 2004, 2003 and 2002, in accordance with SEC guidelines. The December 31, 2004 and 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 the fiscal year ended May 31, 2004 more than tripled the estimated proved reserves over the previous year. 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 the Company has proved undeveloped oil reserves, they are insignificant, so no effort was made to calculate such reserves as of December 31, 2004, May 31, 2004 or May 31, 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 transition period ended December 31, 2004 or the fiscal years ended May 31, 2004, 2003 and 2002.

	December 31,	May 31,		
	2004	2004	2003	2002
Proved Developed Gas Reserves (mcf)	81,467,300	62,558,900	14,016,064	6,356,220
Proved Undeveloped Gas Reserves (mcf)	68,376,600	71,017,300	14,254,570	8,513,750
Total Proved Gas Reserves (mcf)	149,843,900	133,576,200	28,270,634	14,869,970
Proved Developed Oil Reserves (bbl)	47,834	57,105	43,083	45,944
Proved Undeveloped Oil Reserves (bbl)	-	-	-	177,262
Total Proved Oil Reserves (bbl)	47,834	57,105	43,083	223,206
Future Net Cash Flow (after operating expenses)	$611,106,300	$482,745,600	$95,572,500	$25,854,629
Present Value of Future Net Cash Flow	$401,100,700	$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 future net cash flow and present value of future net cash flow amounts are estimates based upon current prices at the time the reports were prepared and do not take into account the effects of the Company's natural gas hedging program.

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 a lesser extent, 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 subject to available capital, 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.

Gas Production Statistics	Seven Months Ended December 31,	Years Ended May 31,		
	2004	2004	2003	2002
Net gas production (mcf)	5,013,911	5,530,208	1,488,679	508,077
Avg wellhead gas price, net (per mcf)	\$4.78	\$5.03	\$5.42	\$1.62
Average production cost (per mcf)	\$1.15	\$1.24	\$1.29	\$0.57
Net revenue (per mcf)	\$3.63	\$3.79	\$4.13	\$1.05

The natural gas production volumes for the transition period ended December 31, 2004 and the 2004 fiscal year include the Devon acquisition beginning December 22, 2003 and the Perkins/Willhite acquisition beginning June 1, 2003 and natural gas production volume for the 2003 fiscal year includes STP production beginning November 1, 2002.

Oil Production Statistics	Seven Months Ended December 31,	Years Ended May 31,		
	2004	2004	2003	2002
Net oil production (bbls)	5,551	8,549	14,123	11,954
Average wellhead oil price (per bbl)	\$42.28	\$37.94	\$19.91	\$19.12
Average production cost (per bbl)	\$16.90	\$16.89	\$16.74	\$20.02
Net revenue (per bbl)	\$25.38	\$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, subsequent to calendar year 2005, the Company will 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:

	Seven Months Ended December 31, 2004 (1)		Years Ended May 31,											
	2004 (1)		2004				2003				2002	
	Gas		Oil		Gas		Oil		Gas		Gas & Oil	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells Drilled:												
Dry	-	-	-	-	-	-	-	-	-	-	4	4
Development Wells Drilled:												
Capable of Production	117	114	-	-	138	132	1	1	45	45	33	25
Dry	-	-	-	-	2	2	-	-	1	1	2	2
Re-completion of Old Wells:												
Capable of Production	38	38	-	-	-	-	-	-	-	-	4	1
Wells Abandoned	(11)	(11)	(2)	(2)	-	-	(13)	(13)	(21)	(18)	(1)	(1)
Acquired Devon wells 12/22/03	-	-	-	-	337	337	-	-	-	-	-	-
Acquired STP1 1/1/02	-	-	-	-	-	-	-	-	108	105	-	-
Other Wells Acquired	11	11	-	-	-	-	-	-	9	8	-	-
Net increase in Capable Wells	117	114	(2)	(2)	477	471	(12)	(12)	143	140	36	28

(1) No change to oil wells for the seven months ended December 31, 2004.

The Company's coal bed 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 coal bed methane well. By abandoning the marginal or non-commercial wells, the Company is more focused on its more profitable coal bed methane wells. The 330 new natural gas wells drilled for the seven-month transition period ended December 31, 2004 reflect an average drilling activity level of 47 wells per month. The Company expects to drill no more than 159 wells for calendar year 2005. The limited number of wells to be drilled in the 2005 calendar year is due to the Company's focus on connecting its significant inventory of drilled, but not connected wells, re-completions of existing wells to increase production and bank covenant restrictions regarding capital expenditures and drilling activity. (see Item 6. "Management's Discussion and Analysis or Plan of Operation – Capital Resources and Liquidity – UBS Credit Facility"). Subsequent to calendar year 2005, the Company plans to drill approximately 32 wells per month, subject to capital being available for such expenditures.

Since December 31, 2004, the Company has drilled 26 wells and connected 152. As of April 6, 2005, the Company was not drilling any wells and approximately 54 wells were in the process of being completed over the next thirty-day period.

Delivery Commitments

Natural Gas. The Company does not have long-term delivery commitments. The Company markets its own natural gas and more than 95% 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 the transition period ended December 31, 2004 or the fiscal years ended May 31, 2004 or 2003.

Oil. The Company's oil is currently being sold to Coffeyville Refining. Previously, it had been sold to Plains Marketing, L.P. The Company does not have a long-term contract for its oil sales.

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 December 31, 2004. See Note 17 of the notes to consolidated financial statements appearing elsewhere in this document.

	Years Ending December 31,				
	2005	2006	2007	2008	Total
	(dollars in thousands, except price data)				
Natural Gas Swaps:					
Contract vols (MMBtu)	5,474,000	5,614,000	-	-	11,088,000
Weighted-avg fixed price per MMBtu (1)	$ 4.69	$ 4.53	-	-	$ 4.61
Fixed-price sales	$ 25,645	$ 25,433	-	-	$ 51,078
Fair value, net	$ (8,579)	$ (9,096)	-	-	$ (17,675)
Natural Gas Collars:					
Contract vols (MMBtu):					
Floor	3,041,000	1,825,000	3,650,000	2,928,000	11,444,000
Ceiling	3,041,000	1,825,000	3,650,000	2,928,000	11,444,000
Weighted-avg fixed price per MMBtu (1):					
Floor	$ 5.18	$ 5.30	$ 4.83	$ 4.50	$ 4.91
Ceiling	$ 6.23	$ 6.35	$ 5.83	$ 5.52	$ 5.94
Fixed-price sales (2)	$ 18,946	$ 11,589	$ 21,279	$ 16,163	$ 67,977
Fair value, net	$ (934)	$ (768)	$ (1,754)	$ (1,346)	$ (4,802)
Total Natural Gas Contracts:					
Contract vols (MMBtu)	8,515,000	7,439,000	3,650,000	2,928,000	22,532,000
Weighted-avg fixed price per MMBtu (1)	$ 5.24	$ 4.98	$ 5.83	$ 5.52	$ 5.28
Fixed-price sales (2)	$ 44,591	$ 37,022	$ 21,279	$ 16,163	$ 119,055
Fair value, net	$ (9,513)	$ (9,864)	$ (1,754)	$ (1,346)	$ (22,477)

(1) The prices to be realized for hedged production are expected to vary from the prices shown due to basis.
(2) 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 statements.

Pipeline Operations

The Company owns and operates an approximate 1,000 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 that are owned by the Company and 51 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 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 the transition period ended December 31, 2004, the Company was constructing approximately 124 miles of gas pipeline systems including gas trunk lines and gas gathering pipelines ranging in size from 20" to 6". 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 were located near the Company's 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 the transition period ended December 31, 2004 and for each of the last three fiscal years.

	Seven Months Ended December 31,	May 31,		
	2004	2004	2003	2002
Pipeline Natural Gas Volumes (mcf)	7,004,000	8,157,000	2,699,000	1,415,000

The natural gas volumes for the transition period ended December 31, 2004 and for fiscal year 2004 include the Devon acquisition beginning December 22, 2003 and the Perkins/Willhite acquisition beginning June 1, 2003. The natural gas volumes for fiscal year 2003 include STP volumes beginning November 1, 2002. As of December 31, 2004, the total daily capacity was approximately 70 mmcf and the total utilization was approximately 34 mmcf or 49%.

Service Operations

The Company has an experienced staff of 171 field employees in offices located in Chanute and Howard, Kansas and Lenapah, Oklahoma. The headquarters office in Oklahoma City is staffed with 21 executive and administrative personnel.

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, stimulation assets and construction equipment. The Company also owns a repair and fabrication shop that is located in Benedict, Kansas. The Company utilizes third party contractors on an "as needed" basis to supplement the Company's field personnel.

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 other than transportation of certain third party production volumes.

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 drilling wells and operating wells and gathering systems; maintaining bonding requirements in order to drill and operate wells; regulating the location of and production from wells; prescribing the methods of drilling, completing, and plugging wells; regulating the surface use and restoration of properties upon which wells are drilled; requiring the plugging and abandoning of wells; and regulating the disposal of fluids used and produced in connection with drilling and production operations.

The Company's operations are also subject to various state conservation laws and regulations. These include regulations relating to: (1) the amount and rate of production of oil and gas from wells; (2) the spacing and density of wells; (3) the unitization or pooling of natural gas and oil properties; (4) the drilling and operation of disposal and enhanced recovery wells; (5) the operation of secondary recovery projects; and (6) air emissions.

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

The Company's cost of maintaining environmental compliance is less than $150,000 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 April 6, 2005, the Company had 192 employees. None of the Company's 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 in Suite 200 at 5901 N. Western in Oklahoma City, Oklahoma 73118 and the space was rented from Mr. Cash, who is the Chairman, Chief Executive Officer and a director of the Company for the amount of $3,050 monthly.

The Company also owns a building located at 211 West 14th Street in Chanute, Kansas, 66720 that is used as an administrative office, an operations terminal and a repair facility. Prior to November 2004, an administrative office for the Company and its subsidiaries was located at 701 East Main Street in Benedict, Kansas 66714. It was 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, 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. The Company also leases an operational office that is located east of Chanute, Kansas.

Where To Find Additional Information

Additional information about the Company can be found on its website at www.qrcp.net. The Company also provides on its website the Company's filings with the SEC, including its 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

See Note 9 – Contingencies, in notes to consolidated financial statements.

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 transition period ended December 31, 2004.

PART II

ITEM 5. MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

The Company's common stock trades in the over-the-counter market under the symbol "QRCP". From June 8, 1999 until February 23, 2004, the Company's common stock traded on the OTC Bulletin Board. From February 23, 2004 until November 15, 2004, the Company's common stock was traded in the "pink sheets". Since November 15, 2004, the Company's common stock has traded 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 and the transition period ended December 31, 2004. The prices in the table reflect inter-dealer prices, without retail markup, markdown or commission and may not represent actual transactions.

	Fiscal Quarter and Period Ended	
	High Price	Low Price
December 31, 2004 (month ended)	$ 6.25	$ 5.75
November 30, 2004	$ 7.25	$ 4.30
August 31, 2004	$ 4.85	$ 3.50
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 April 6, 2005 was $4.00.

Record Holders

Common Stock. There are 950,000,000 shares of common stock authorized for issuance. As of March 29, 2005, there were 14,249,694 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 April 6, 2005, 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 notes 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

The following discussion of financial condition and results of operations should be read in conjunction with the consolidated financial statements and the notes to the 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 consolidated 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) and the stimulation asset acquisition (Consolidated) during the transition period ended December 31, 2004 into one new organization, has allowed the Company to support new levels of development and operational activities. This integration has been accomplished with all of the Company's personnel now comprising an effective new team.

The Company's 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 operating income in fiscal year 2004 as a result of increased natural gas prices over the levels realized in fiscal 2003 and the transition period reflects an improvement on an annualized basis as compared to fiscal year ended May 31, 2004. 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 and a full year of operations from the STP acquisition that was completed in November 2002. The increase in total revenues for the transition period resulted from higher product prices (before hedge settlements) for natural gas and on an annualized basis, production volumes increased from a full year of operations from the Devon property acquisition. Operating results were also favorably affected by the increased level of new well development that was achieved during the transition period as a result of the increased funding of the Company's drilling program using the credit facilities from UBS. See Items 1 and 2. "Description of Business and Properties."

At December 31, 2004, Quest had an interest in 824 natural gas and oil wells (gross) and natural gas and oil leases on approximately 517,000 gross acres. Management believes that the proximity of the 1,000 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 159 wells planned to be drilled during calendar year 2005 and thereafter, 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 or that adequate sources of capital will be available.

Significant Developments During The Seven Months Ended December 31, 2004

The Company has continued its development of new wells and the construction of supporting pipeline infrastructure. During the seven months ended December 31, 2004, the Company drilled 330 new gas wells (gross). The Company also connected 117 new gas wells (gross) into its gas gathering pipeline network during the same seven-month period. On December 31, 2004, the Company had 795 gas wells (gross) that it was operating and 206 gas wells (gross) that it was in the process of completing and connecting to its gas gathering pipeline system. In order to connect these new wells to the Company's pipeline network, the Company has undertaken the construction of approximately 124 miles of pipeline to gather gas and water from the new wells.

On July 22, 2004, Quest Cherokee entered into a syndicated credit facility arranged and syndicated by UBS Securities LLC, with UBS AG, Stamford Branch as administrative agent (the "UBS Credit Agreement"). The UBS Credit Agreement originally provided for a $120 million six year term loan that was fully funded at closing and a $20 million five year revolving credit facility that could be used to issue letters of credit and fund future working capital needs and general corporate purposes. At closing, approximately $5 million of the UBS Revolving Loan was utilized for the issuance of letters of credit. The UBS Credit Agreement also contains a $15 million "synthetic" letter of credit facility that matures in December 2008, which provides credit support for Quest Cherokee's natural gas hedging program. A portion of the proceeds from the term loan were used to repay Quest Cherokee's existing credit facilities. In January 2005, Quest Cherokee determined that it was not in compliance with the leverage and interest coverage ratios in the UBS Credit Agreement for the quarter ended November 30, 2004. These defaults have been waived by lenders and Quest Cherokee is currently in compliance under the UBS Credit Agreement as amended on February 22, 2005. See "—Liquidity and Capital Resources".

The Company entered into an asset purchase agreement and a real estate purchase agreement on August 19, 2004 to acquire certain assets from Consolidated Oil Well Services in the amount of $4.1 million. The assets consisted of cementing, acidizing and fracturing equipment and a related office building and storage facility in Chanute, Kansas. The acquisition closed on September 15, 2004 and was funded with a portion of the remaining net proceeds from the $120 million term loan under the UBS Credit Agreement.

Additionally, the Company acquired 8 non-producing wells and approximately 8,000 acres in the Cherokee Basin on August 6, 2004 for $750,000.

Results of Operations

Seven months ended December 31, 2004 compared to the seven months ended December 31, 2003

The Company has changed its fiscal year-end from May 31 to December 31. As a result of this change, the Company has prepared financial statements for the seven-month transition period ended December 31, 2004. Accordingly, the following discussion of results of operations will compare audited balances for the seven months ended December 31, 2004 to the unaudited balances for the seven months ended December 31, 2003, as follows:

	Seven months ended December 31,	
	2004	2003
		(unaudited)
Oil and gas sales	$ 24,201,000	$ 8,755,000
Gas pipeline revenue	1,918,000	1,289,000
Other revenue and expense	37,000	(1,356,000)
Total revenues	26,156,000	8,688,000
Oil and gas production	5,389,000	2,267,000
Pipeline operating	3,653,000	1,140,000
General & administrative expense	2,681,000	831,000
Depreciation, depletion & amortization	7,671,000	2,235,000
Other costs of revenues	--	(8,000)
Total costs and expenses	19,394,000	6,465,000
Operating income	6,762,000	2,223,000
Change in derivative fair value	(1,487,000)	3,312,000
Interest expense	(10,147,000)	(2,377,000)
Interest income	9,000	--
Income (loss) before income taxes	(4,863,000)	3,158,000
Income tax (expense)	--	(1,263,000)
Net income (loss)	$ (4,863,000)	$ 1,895,000

Total revenues of $26.2 million for the seven months ended December 31, 2004 represents an increase of 201% when compared to total revenues of $8.7 million for the seven months ended December 31, 2003. This increase was achieved by a combination of the additional producing wells from the Devon acquisition in December 2003 and the Company's aggressive new well development program.

The increase in natural gas and oil sales from $8.8 million for the seven months ended December 31, 2003 to $24.2 million for the seven months ended December 31, 2004 and the increase in natural gas pipeline revenue from $1.3 million to $1.9 million resulted from the Devon asset acquisition and the additional wells and pipelines acquired or completed during the past twelve months. The Devon asset acquisition and the additional wells acquired or completed contributed to the production of 5,014,000 mcf of net gas for the seven months ended December 31, 2004, as compared to 1,815,000 net mcf produced for the seven months ended December 31, 2003. The Company's product prices before hedge settlements on an equivalent basis (mcfe) increased from $4.82 mcfe average for the 2003 period to $5.74 mcfe average for the 2004 period. Accounting for hedge settlements, the product prices increased from $4.08 mcfe average for the 2003 period to $4.83 mcfe average for the 2004 period. 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 January 1, 2005, the Company had entered into hedging transactions covering a total of approximately 22.5 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 revenue for the seven months ended December 31, 2004 was $37,000 as compared to other expense of $1.4 million for the seven months ended December 31, 2003, resulting from recording the gain or loss on hedge settlements for the two comparative periods.

The operating costs for the seven months ended December 31, 2004 totaled approximately $5.4 million as compared to operating costs of approximately $2.3 million incurred for the seven months ended December 31, 2003. Operating costs per mcf for the 2004 period were $1.07 per mcf as compared to $1.25 per mcf for the 2003 period, representing a 14% decrease. Pipeline operating costs for the seven months ended December 31, 2004 totaled approximately $3.7 million as compared to pipeline operating costs of $1.1 million incurred for the seven months ended December 31, 2003. The increase in operating costs are due to the Devon asset acquisition 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 $2 million is a result of the increased number of producing wells and miles of pipeline 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 asset acquisition.

General and administrative expenses increased to approximately $2.7 million for the seven months ended December 31, 2004 from $831,000 in the prior seven month period due primarily to the Devon asset acquisition, 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 $10.1 million for the seven months ended December 31, 2004 from $2.4 million for the seven months ended December 31, 2003, due to the increase in the Company's outstanding borrowings related to the Devon acquisition and equipment, development and leasehold expenditures from the Company's aggressive drilling and development program during the transition period.

Change in derivative fair value was a non-cash net loss of $1.5 million for the seven months ended December 31, 2004, which included a $269,000 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 period, a $565,000 net gain attributable to the reversal of contract fair value gains and losses recognized in earnings prior to actual settlement, and a loss of $1.8 million relating to hedge ineffectiveness. Change in derivative fair value was a non-cash net gain of $3.3 million for the seven months ended December 31, 2003, which was attributable to the change in fair value of cash flow hedges that did not meet the effectiveness guidelines of SFAS 133 for the period. Amounts recorded in this caption represent non-cash gains and losses created by valuation changes in derivatives that 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 a net loss of $3.4 million before income taxes and before the change in derivative fair value of $1.5 million for the seven months ended December 31, 2004, compared to a net loss of $154,000 before income taxes and before the change in derivative fair value of $3.3 million in the previous seven month period.

No income tax expense or benefit resulted for the seven months ended December 31, 2004 compared to the income tax expense of $1.3 million for the seven months ended December 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 $4.9 million for the seven months ended December 31, 2004 as compared to net income of $1.9 million for the seven months ended December 31, 2003.

Fiscal year ended May 31, 2004 compared to fiscal year ended May 31, 2003

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 million related to the retirement of the Wells Fargo credit facilities.

Change in derivative fair value was a non-cash net loss of $2 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 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

Analysis of cash flows. As stated above, the Company changed its year-end from May 31 to December 31. As a result of this change, the Company has prepared financial statements for the seven-month transition period ended December 31, 2004. Accordingly, the following analysis of cash flows will cover the seven months ended December 31, 2004 compared to the seven months ended December 31, 2003, as follows:

	Seven months ended December 31, 2004	Seven months ended December 31, 2003 (unaudited)
Cash flows from operating activities:		
Net income (loss)	$ (4,863,000)	$ 1,895,000
Adjustments to reconcile net income (loss) to cash provided by operations:		
Depreciation & depletion	8,033,000	2,235,000
Accrued interest subordinated notes	4,866,000	210,000
Change in derivative fair value	1,487,000	(3,312,000)
Cumulative effect of accounting change	-	47,000
Deferred income taxes	-	1,263,000
Accretion of line of credit	-	1,204,000
Stock issued for services	-	62,000
Stock issued for director fees	62,000	-
Amortization of loan origination fees	530,000	172,000
Other	191,000	-
Change in assets and liabilities:		
Accounts receivable	893,000	(2,397,000)
Other receivables	85,000	-
Other current assets	16,000	-
Inventory	208,000	130,000
Accounts payable	13,628,000	1,201,000
Revenue payable	222,000	836,000
Accrued expenses	126,000	-
Net cash provided by operating activities	25,484,000	3,546,000
Cash flows from investing activities:		
Acquisition of proved gas & oil properties-Devon	-	(111,220,000)
Acquisition of gas gathering pipelines-Devon	-	(21,864,000)
Equipment, development & leasehold costs	(48,287,000)	(6,425,000)
Other assets	(527,000)	(188,000)
Net cash used in investing activities	(48,814,000)	(139,697,000)
Cash flows from investing activities:		
Long-term debt	136,118,000	89,450,000
Repayments of note borrowings	(104,732,000)	(19,500,000)
Proceeds from subordinated debt	-	51,000,000
Refinancing costs-UBS	(4,942,000)	-
Accounts payable-Devon holdback	-	12,417,000
Dividends paid	(6,000)	(5,000)
Proceeds from the issuance of common stock	480,000	500,000
Change in other long-term liabilities	(638,000)	-
Net cash provided by financing activities	26,280,000	133,862,000
Net increase in cash	2,950,000	(2,289,000)
Cash, beginning of period	3,508,000	2,689,000
Cash, end of period	$ 6,458,000	$ 400,000

At December 31, 2004, the Company had current assets of $13.9 million, a working capital deficit (current assets minus current liabilities, excluding the short-term derivative asset and liability of $202,000 and $9.5 million, respectively) of $9.5 million and had generated $25.5 million net cash from operations during the seven months ended December 31, 2004.

During the seven months ended December 31, 2004, a total of approximately $48.8 million was invested in new natural gas wells and properties, new pipeline facilities, and other additional capital items. This investment was funded by operational cash flow, an increase of approximately $31.4 million in long-term debt and the $12 million of additional notes issued to ArcLight during February 2005. Additionally, the Company borrowed $5 million of additional term loans under the UBS Credit Agreement and paid down $3 million of the outstanding balance under its revolving credit facility during February 2005.

Net cash provided from operating activities increased substantially from $3.5 million for the seven months ended December 31, 2003 to $25.5 million for the seven months ended December 31, 2004 due primarily to the expanded operations of the Company as discussed above.

The Company's working capital deficit (current assets minus current liabilities, excluding the short-term derivative asset and liability of $202,000 and $9.5 million, respectively) was $9.5 million at December 31, 2004, compared to a working capital deficit of $132,000, (excluding the short-term derivative asset and liability of $917,000 and $2.6 million, respectively) at December 31, 2003. The change in working capital, resulting in a deficit, is due to the expanded operations from the completion of the Devon asset acquisition and the Company's significant new well and pipeline development activities during the last half of calendar year 2004. Additionally, accounts receivable, inventory, accounts payable, oil and gas payable and accrued expenses balances increased as the Company expanded its operations. There is a substantial increase in both receivables and payables on the balance sheet for December 31, 2004 as compared to December 31, 2003. This increase is largely due to the substantial increase in operating activity conducted by the Company that resulted in the $7.7 million working capital deficit. A significant portion of the accounts payable as of December 31, 2004 were funded with the proceeds of additional term loan borrowings and additional subordinated notes issued in February 2005 (See – "UBS Credit Facility" and "ArcLight Transaction" below).

The Company intends to focus on re-completions and developing up to 159 additional new wells to be drilled and completed using the resources generated by its operations (subject to compliance with the limitations contained in the UBS Credit Agreement – See Item 6. "Management's Discussion and Analysis or Plan of Operation – Capital Resources and Liquidity – UBS Credit Facility"). However, no assurances can be given that such sources will be sufficient to fund the proposed capital expenditures for calendar year 2005. Subsequent to calendar year 2005, the Company intends to drill approximately 380 wells per year, which management currently estimates will require a capital investment of approximately $32 million per year to drill and develop. Management currently estimates that the Company would be able to drill and develop approximately 310 of these new wells during year 2006 utilizing cash flow from operations and that the Company will need to obtain additional funds for any additional wells. The Company could seek to borrow additional funds or sell equity securities. However, no assurances are given that such sources will be sufficient to fund the Company's anticipated level of new well development.

The Company has determined that it is not feasible to develop the property leased by it in western Kentucky and has elected to not renew the lease. Developing this property could have required the Company to obtain significant additional capital resources. Since this property was outside of Quest Cherokee, the assets and financial resources of Quest Cherokee would not be available to support the development of this property.

The Company acquired approximately 80 miles of an inactive oil pipeline for approximately $1 million during August 2004. 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 consisted 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 Company's current credit facility. See "—UBS Credit Facility."

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, 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. On July 22, 2004, the Bank One credit facilities were refinanced with a new credit facility arranged and syndicated by UBS Securities LLC, with UBS AG, Stamford Branch as administrative agent. See "—UBS Credit Facility".

UBS Credit Facility

On July 22, 2004, Quest Cherokee entered into a syndicated credit facility arranged and syndicated by UBS Securities LLC, with UBS AG, Stamford Branch as administrative agent (the "UBS Credit Agreement"). The UBS Credit Agreement originally provided 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 could be used to issue letters of credit and fund future working capital needs and general corporate purposes (the "UBS Revolving Loan"). As of December 31, 2004, Quest Cherokee had approximately $15 million of loans and approximately $5 million in letters of credit issued under the

UBS Revolving Loan. Letters of credit issued under the UBS Revolving Loan reduce the amount that can be borrowed there under. The UBS Credit Agreement also contains a $15 million "synthetic" letter of credit facility that matures in December 2008, which provides 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 initially accrued 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 (3.50% for revolving loans and 4.50% 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 4.75% for term loans). In connection with the amendment to the UBS Credit Agreement in February 2005 discussed below, the applicable margin on borrowings under the UBS Credit Agreement was increased by 1% until Quest Cherokee's total leverage ratio is less than 4.0 to 1.0. 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 4.75% 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 (other than the Subordinated Notes) less up to $10 million of unrestricted cash.

The UBS Credit Agreement was initially 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. In connection with the formation of Quest Cherokee Oilfield Service, LLC ("QCOS") on August 16, 2004, QCOS became a guarantor of the UBS Credit Agreement and pledged its assets as security for its guarantee.

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 (which are described in more detail below); 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.

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 January 2005, Quest Cherokee determined that it was not in compliance with the leverage and interest coverage ratios in the UBS Credit Agreement for the quarter ended November 30, 2004. On February 22, 2005, Quest Cherokee and the lenders under the UBS Credit Agreement entered into an amendment and waiver pursuant to which the lenders waived all of the existing defaults under the UBS Credit Agreement and the UBS Credit Agreement was amended, among other things, as follows:

- an additional $12 million of Subordinated Notes to ArcLight was permitted;
- the UBS Term Loan was increased by an additional $5 million to a total of $125 million;
- the Company cannot drill any new wells until not less than 200 wells have been connected to the Company's gathering system since January 1, 2005 and gross daily production is at least 43 mmcfe/d for 20 of the last 30 days prior to the date of drilling, after which time the Company may drill up to 150 new wells prior to December 31, 2005 as long as the ending inventory of wells-in-progress as of the end of any month does not exceed 250 (as of April 6, 2005, the Company had connected 152 wells since January 1, 2005 and its average gross daily production for the 20 highest days out of the last 30 days was 35,392 mmcfe/d;
- the total leverage ratio for any test period may not exceed:

  5.50 to 1.0 for the first quarter of 2005
  5.00 to 1.0 for the second quarter of 2005
  4.50 to 1.0 for the third quarter of 2005
  3.80 to 1.0 for the fourth quarter of 2005
  3.30 to 1.0 for the first quarter of 2006
  2.90 to 1.0 for the second quarter of 2006
  2.50 to 1.0 for the third quarter of 2006
  2.50 to 1.0 for the fourth quarter of 2006 and thereafter;

- the minimum asset coverage ratio for any test period may not be less than 1.25 to 1.0;
- the minimum interest coverage ratio for any test period may not be less than:

  2.70 to 1.0 for each quarter for the year ended December 31, 2005; and
  3.50 to 1.0 for each quarter for the year ended December 31, 2006 and thereafter;

- the minimum fixed charge coverage ratio for any test period (starting March 2006) may not be less than:

  1.00 to 1.0 for each of the first three quarters of 2006;
  1.10 to 1.0 for the fourth quarter of 2006;
  1.25 to 1.0 for each quarter for the year ended December 31, 2007; and
  1.50 to 1.0 for each quarter thereafter;

- capital expenditures for any test period may not exceed:

  $15 million for the first quarter 2005
  $7.25 million for the second quarter 2005
  $9.5 million for the third quarter 2005
  $13.25 million for the fourth quarter 2005
  $10 million for each quarter for the year ended December 31, 2006; and
  the amount of budgeted capital expenditures for 2007 and thereafter; and

- until the later of December 31, 2005 and the date on which Quest Cherokee's total leverage ratio is less than 3.5 to 1.0, the UBS Revolving Loan may only be used for working capital purposes.

ArcLight Transaction

In connection with the Devon asset acquisition, the Company issued a $51 million junior subordinated promissory note from ArcLight (the "Original Note") pursuant to the terms of a note purchase agreement. The Original Note was purchased at par. The Original 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 Original 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.

On February 11, 2005, Quest Cherokee and ArcLight amended and restated the note purchase agreement to provide for the issuance to ArcLight of up to $15 million of additional 15% junior subordinated promissory notes (the "Additional Notes" and together with the Original Notes, the "Subordinated Notes") pursuant to the terms of an amended and restated note purchase agreement. Also on February 11, 2005, Quest Cherokee issued $5 million of Additional Notes to ArcLight (the "Second Issuance").

The Subordinated Notes, together with all accrued and unpaid interest, were originally due on December 22, 2008. In connection with the UBS Credit Agreement, the maturity date of the Subordinated Notes 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.

In the event that Quest Cherokee is dissolved on or before February 11, 2008 (an "Early Liquidation Event"), the holders of the Subordinated Notes 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 Notes and $88.2 million (140% of the original principal amount of the Subordinated Notes).

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

Under the UBS Credit Agreement, no payments may be made on the Subordinated Notes nor may any distributions be made to the members of Quest Cherokee until after the December 31, 2004 reserve report has been delivered to the lenders. After that date, payments may be made with respect to the Subordinated Notes 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.

In connection with the purchase of the Subordinated Notes, 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 was initially to be distributed generally 85% to the holders of the Subordinated Notes and 15% to the holders of the Class B units until the Subordinated Notes have been repaid. Thereafter, the net cash flow of Quest Cherokee was to be distributed generally 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 was to be distributed generally 30% to the holders of the Class A units and 70% to the holders of the Class B units.

As a condition to the Second Issuance, the amended and restated limited liability company agreement was amended to provided that (1) the portion of Quest Cherokee's net cash flow that is required to be used to repay the Subordinated Notes was increased from 85% to 90%, and the portion of the net cash flow distributable to the Company's subsidiaries, as the holders of all of Quest Cherokee's Class B units, was decreased from 15% to 10%, until the Subordinated Notes have been repaid and (2) after the Subordinated Notes have been repaid and ArcLight has received a 30% internal rate of return on its investment in Quest Cherokee, Quest Cherokee's net cash flow will be distributed generally 35% to ArcLight (as the holder of the Class A Units) and 65% to the Company's subsidiaries (as 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.

The February 11, 2005 amended and restated note purchase agreement also provided for Quest Cherokee to issue to ArcLight Additional Notes in the principal amount of $7 million (the "Third Issuance") upon Quest Cherokee obtaining a waiver from the lenders under the UBS Credit Agreement with respect to Quest Cherokee's default under the credit agreement and an amendment to the credit agreement to permit the issuance of Additional Notes to ArcLight. On February 22, 2005, Quest Cherokee obtained the necessary waivers and amendments to the UBS Credit Agreement and closed on the Third Issuance. At the same time, Quest Cherokee borrowed $5 million of additional term loans under the UBS Credit Agreement and paid down $3 million of the outstanding balance under the revolver.

Finally, the amended and restated note purchase agreement provides Quest Cherokee with the option to issue to ArcLight Additional Notes in the principal amount of $3 million (the "Fourth Issuance"). In the event of the Fourth Issuance:

(i) the interest rate on the Subordinated Notes would increase from 15% to 20%;

(ii) the portion of Quest Cherokee's net cash flow that is required to be used to repay the Subordinated Notes would be further increased from 90% to 95%, and the portion of the net cash flow distributable to the Company's subsidiaries, as the holders of all of Quest Cherokee's Class B units, would be further decreased from 10% to 5%, until the Subordinated Notes have been repaid; and

(iii) after the Subordinated Notes have been repaid and ArcLight has received a 30% internal rate of return on its investment in Quest Cherokee, Quest Cherokee's net cash flow would be distributed 40% to ArcLight (as the holder of the Class A Units) and 60% to the Company's subsidiaries (as the holders of the Class B Units).

It is not currently anticipated that Quest Cherokee will exercise its option to issue any Additional Notes in a Fourth Issuance.

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. Initially, the Company consolidated all of its employees into QES. In September 2004, QCOS was formed to acquire the stimulation assets from Consolidated. At that time, the Company's vehicles and equipment were transferred to QCOS and the costs associated with field employees, first level supervisors, exploration, development and operation of the Company's properties and certain other direct charges are now paid directly by QCOS while QES continues to employ all of the Company's non-field employees (other than first level supervisors). 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 is currently reviewing the management fee to determine if it will be sufficient to cover such expenses for the foreseeable future.

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 had 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 December 31, 2004 of $373,000. The $100,000 note matured on November 4, 2004, bore interest at the annual rate of 7% per annum and was secured by the inventory of parts and materials. As part of the restructuring , Quest Cherokee assumed the obligations under these notes.

Contractual Obligations

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

	Total	2005	2006-2007	2008-2009	thereafter
Term B Note	$ 119,700,000	$ 1,200,000	$2,400,000	$ 2,400,000	$ 113,700,000
Revolving Line of Credit	15,000,000	--	--	15,000,000	--
Notes payable	1,713,000	554,000	927,000	134,000	98,000
Convertible debentures	50,000	50,000	--	--	--
Subordinated debt	59,325,000	--	--	--	59,325,000
Total	$ 195,788,000	$ 1,804,000	$3,327,000	$ 17,534,000	$173,123,000

In February 2005, the Company (a) borrowed an additional $5 million of Term B Notes that will be due on 2010 and (b) issued an additional $12 million of subordinated debt that will be due in 2010. If interest on the subordinated notes is not paid in cash, it will be added to the principle balance of the subordinated notes and if no payments are made on the subordinated notes, the principle amount would be $196.1 million in 2010 (taking into account the additional $12 million of subordinated notes issued on February 2005).

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 consolidated financial statements.

Certain Capital Transactions

During the seven months ended December 31, 2004 and 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.

On August 23, 2004, the Company granted a total of 25,000 shares of its common stock to Mr. John Garrison as compensation for services on the Company's audit committee during the period from June 6, 2003 to May 31, 2005. Of the shares granted, 17,000 shares were issued with a value of $62,000 for financial reporting purposes. The remaining 8,000 shares are restricted and subject to forfeiture in the event that Mr. Garrison resigns from the Company's audit committee before May 31, 2005 and will be issued when the restrictions have lapsed. The issuance of the shares is exempt from registration pursuant to Section 4(2) of the Securities Act.

On November 8, 2004, 120,000 shares of common stock sold for cash with a value of $480,000 were issued to the following accredited investors: Fred B. Oates, Theodore Wannamaker Gage, Jr., Kate O. Dargan, Frank A. Jones, Larry Joe Vin Zant, Kenneth A. and Victoria M. Hull, Whitney and Elizabeth Vin Zant, Mark N. Vin Zant. These transactions were exempt from registration pursuant to either Section 4(2) of the Securities Act or Regulation D. These securities were sold without a general solicitation, and to accredited investors. The securities were issued with a legend restricting resale.

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 December 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 sheets of QUEST RESOURCE CORPORATION and subsidiaries as of December 31, 2004 and May 31, 2004, and the related consolidated statements of operations, stockholders' equity, and cash flows for the seven months ended December 31, 2004 and 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 (United States). 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, 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 December 31, 2004 and May 31, 2004, and the consolidated results of their operations and cash flows for the seven months ended December 31, 2004 and 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
March 4, 2005

QUEST RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS

	December31, 2004	May 31, 2004
Current assets:		
Cash	$ 6,458,000	$ 3,508,000
Accounts receivable, trade	6,204,000	7,097,000
Other receivables	524,000	609,000
Deposits on acquisition	--	216,000
Other current assets	241,000	257,000
Short-term derivative asset	202,000	--
Inventory	284,000	492,000
Total current assets	13,913,000	12,179,000
Property and equipment, net of accumulated depreciation of $1,245,000 and $832,000	8,433,000	2,570,000
Pipeline assets, net of accumulated depreciation of $2,207,000 and $1,774,000	42,552,000	36,488,000
Pipeline assets under construction	12,537,000	--
Oil and gas properties:		
Properties being amortized	154,427,000	123,161,000
Properties not being amortized	16,707,000	24,662,000
	171,134,000	147,823,000
Less: Accumulated depreciation, depletion and amortization	(16,069,000)	(8,881,000)
Net property, plant and equipment	155,065,000	138,942,000
Other assets, net	5,141,000	196,000
Long-term derivative asset	321,000	--
Total assets	$ 237,962,000	$ 190,375,000

LIABILITIES AND STOCKHOLDERS' EQUITY

	December31, 2004	May 31, 2004
Current liabilities:		
Accounts payable	$ 17,337,000	$ 3,714,000
Revenue payable	3,507,000	3,285,000
Accrued expenses	588,000	462,000
Current portion of notes payable	1,804,000	336,000
Short-term derivative liability	9,513,000	10,087,000
Total current liabilities	32,749,000	17,884,000
Non-current liabilities:		
Long-term derivative liability	12,964,000	9,701,000
Asset retirement obligation	871,000	717,000
Convertible debentures	50,000	50,000
Acquisition holdback payable	--	638,000
Notes payable	136,413,000	105,027,000
Less current maturities	(1,804,000)	(336,000)
Non-current liabilities	148,494,000	115,797,000
Subordinated debt (including accrued interest)	59,325,000	54,459,000
Total liabilities	240,568,000	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 at December 31 and May 31, 2004	--	--
Common stock, $.001 par value, 950,000,000 shares authorized, 14,249,694 and 14,112,694 shares issued and outstanding at December 31 and May 31, 2004	14,000	14,000
Additional paid-in capital	17,184,000	16,642,000
Accumulated other comprehensive income	(11,143,000)	(10,629,000)
Accumulated deficit	(8,661,000)	(3,792,000)
Total stockholders' equity	(2,606,000)	2,235,000
Total liabilities and stockholders' equity	$ 237,962,000	$ 190,375,000

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

QUEST RESOURCE CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Seven Months Ended December 31, 2004	Year Ended May 31, 2004	Year Ended May 31, 2003
Revenue:			
Oil and gas sales	$ 24,201,000	$ 28,147,000	$ 8,345,000
Gas pipeline revenue	1,918,000	2,707,000	632,000
Other revenue and expense	37,000	(843,000)	(879,000)
Total revenues	26,156,000	30,011,000	8,098,000
Costs and expenses:			
Oil and gas production	5,389,000	6,835,000	1,923,000
Pipeline operating	3,653,000	3,506,000	912,000
General and administrative expenses	2,681,000	2,555,000	977,000
Depreciation, depletion and amortization	7,671,000	7,650,000	1,822,000
Other costs of revenues	--	--	56,000
Total costs and expenses	19,394,000	20,546,000	5,690,000
Operating income	6,762,000	9,465,000	2,408,000
Other income (expense):			
Change in derivative fair value	(1,487,000)	(2,013,000)	(4,867,000)
Sale of assets	--	(6,000)	(3,000)
Interest expense	(10,147,000)	(8,057,000)	(727,000)
Interest income	9,000	1,000	--
Total other income and expense	(11,625,000)	(10,075,000)	(5,597,000)
Loss before income taxes	(4,863,000)	(610,000)	(3,189,000)
Deferred income tax benefit (expense)	--	245,000	(374,000)
Net loss before cumulative effect of accounting change	(4,863,000)	(365,000)	(3,563,000)
Cumulative effect of accounting change, net of income tax of $19,000	--	(28,000)	--
Net loss	(4,863,000)	(393,000)	(3,563,000)
Preferred stock dividends	(6,000)	(10,000)	(10,000)
Net loss available to common shareholders	$ (4,869,000)	$ (403,000)	$ (3,573,000)
Loss per common share – basic:			
Loss before cumulative effect of accounting change	$ (0.34)	$ (0.03)	$ (0.35)
Cumulative effect of accounting change	--	--	--
	$ (0.34)	$ (0.03)	$ (0.35)
Loss per common share – diluted:			
Loss before cumulative effect of accounting change	$ (0.34)	$ (0.03)	$ (0.35)
Cumulative effect of accounting change	--	--	--
	$ (0.34)	$ (0.03)	$ (0.35)
Weighted average common and common equivalent shares outstanding:			
Basic	14,153,381	13,970,880	10,236,288
Diluted	14,153,381	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

	Seven Months Ended December 31, 2004	Year Ended May 31, 2004	Year Ended May 31, 2003
Cash flows from operating activities:			
Net income (loss)	$ (4,863,000)	$ (393,000)	$ (3,563,000)
Adjustments to reconcile net income (loss) to cash provided by operations:			
Depreciation	846,000	835,000	210,000
Depletion	7,187,000	6,802,000	1,612,000
Accrued interest subordinated note	4,866,000	3,459,000	--
Change in derivative fair value	1,487,000	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	--	62,000
Stock issued for services	--	94,000	73,000
Amortization of loan origination fees	530,000	172,000	20,000
Amortization of deferred hedging gains	163,000	--	--
Other	28,000	44,000	--
Change in assets and liabilities:			
Accounts receivable	893,000	(4,751,000)	(295,000)
Other receivables	85,000	(1,432,000)	(8,000)
Other current assets	16,000	(257,000)	--
Futures contract	--	--	46,000
Inventory	208,000	(244,000)	(157,000)
Accounts payable	13,628,000	2,302,000	(636,000)
Revenue payable	222,000	2,221,000	557,000
Accrued expenses	126,000	223,000	209,000
Net cash provided by operating activities	25,484,000	12,197,000	4,211,000
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)
Other assets	(527,000)	(393,000)	(192,000)
Equipment, development and leasehold costs	(48,287,000)	(12,628,000)	(7,999,000)
Net cash used in investing activities	(48,814,000)	(146,834,000)	(8,804,000)
Cash flows from financing activities:			
Long term debt	136,118,000	105,000,000	6,573,000
Repayments of note borrowings	(104,732,000)	(21,682,000)	--
Proceeds from subordinated debt	--	51,000,000	--
Convertible debentures	--	--	165,000
Refinancing costs – UBS	(4,942,000)	--	--
Dividends paid	(6,000)	--	--
Change in other long-term liabilities	(638,000)	638,000	--
Proceeds from issuance of common stock	480,000	500,000	467,000
Net cash provided by financing activities	26,280,000	135,456,000	7,205,000
Net increase (decrease) in cash	2,950,000	819,000	2,612,000
Cash, beginning of period	3,508,000	2,689,000	77,000
Cash, end of period	$ 6,458,000	$ 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 SEVEN MONTHS ENDED DECEMBER 31, 2004 AND YEARS ENDED MAY 31, 2004 and 2003

	Preferred Shares	Common Shares	Preferred Stock Par Value	Common Stock Par Value	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Accumulated 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	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
Comprehensive income:								
Net loss							(4,863,000)	(4,863,000)
Other comprehensive loss, net of tax:								
Change in fixed-price contract and other derivative fair value						(5,258,000)		(5,258,000)
Reclassification adjustments-contract settlements						4,744,000		4,744,000
Total comprehensive loss								(5,377,000)
Dividends on preferred stock							(6,000)	(6,000)
Stock sales for cash		120,000			480,000			480,000
Stock issued for services		17,000			62,000			62,000
Balance, December 31, 2004	10,000	14,249,694	$ --	$ 14,000	$ 17,184,000	$ (11,143,000)	$ (8,661,000)	$ (2,606,000)

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 (coal bed methane) in southeastern Kansas and northeastern Oklahoma. Quest operations are currently focused on developing coal bed 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 Cherokee Oilfield Service, LLC, a Delaware limited liability company ("QCOS"),
- 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 and QCOS.

Quest Cherokee owns and operates all of the Company's Cherokee Basin natural gas and oil properties. Quest Cherokee Oilfield Service owns and operates all of the Company's vehicles and equipment and Bluestem owns all of the Company's gas gathering pipeline assets in the Cherokee Basin. QES employs all of the Company's non-field 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 (the "Management Agreement"). The costs associated with field employees, first level supervisors, exploration, development and operation of the properties and certain other direct charges are borne by QCOS. STP owns properties located in 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 owned and controlled by ArcLight, and Class B that is owned and controlled by Quest Resource Corporation though several of its wholly owned subsidiaries. ArcLight acquired the Class A units for $100 in connection with its purchase of $51 million of subordinated notes of Quest Cherokee. The Class B members contributed natural gas and oil properties with an agreed upon value of $51 million. 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 90% to the holders of the subordinated promissory notes and 10% to the holders of 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 35% to the holders of the Class A units and 65% to the holders of the Class B units.

Since the Company is anticipated to ultimately control 65% of the cash flows, the results of operation of Quest Cherokee have been included in these consolidated financial statements. For the period from inception through December 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.

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 consolidated 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 the Company's liquidity is concentrated in cash and derivative instruments that enable the Company to hedge a portion of its exposure to price volatility from producing natural gas and oil. These arrangements expose the Company to credit risk from its counterparties. The Company's accounts receivable are primarily from purchasers of natural gas and oil products. Natural gas sales to one purchaser (ONEOK) accounted for more than 95% of total natural gas and oil revenues for the seven months ended December 31, 2004. The industry concentration has the potential to impact the Company's overall exposure to credit risk, either positively or negatively, in that the Company's 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 is reviewed on an annual basis for impairment and as of December 31, 2004, the Company has not identified any such impairment. Repairs and maintenance are charged to operations when incurred and improvements and renewals are capitalized.

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:

Pipeline	40 years
Buildings	25 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-or-sale. At May 31, 2004 and December 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"). The Company also enters into interest rate swaps and caps to reduce its exposure to adverse interest rate fluctuations. 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 re-designation 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. Also, all changes in fair value of the Company's interest rate swaps and caps are reported in results of operations rather than in other comprehensive income because the critical terms of the interest rate swaps and caps do not comply with certain requirements set forth in SFAS 133.

Although the Company's fixed-price contracts and interest rate swaps and caps 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 and interest rate risks 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 its 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. The Company is unable to predict if and when its pipelines would become completely obsolete and require decommissioning. Accordingly, the Company has recorded no liability or corresponding asset for the pipelines in conjunction with the adoption of SFAS 143 because the future dismantlement and removal dates of the Company's assets and the amount of any associated costs are indeterminable.

Reclassification

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

2. Acquisitions

The Company acquired certain assets from Consolidated Oil Well Services on September 15, 2004 in the amount of $4.1 million. The assets consisted of cementing, acidizing and fracturing equipment and a related office building and storage facility in Chanute, Kansas. The acquisition was funded with a portion of the remaining net proceeds from the $120 million term loan under the UBS Credit Agreement.

The Company formed Quest Cherokee Oilfield Service, LLC ("QCOS") to acquire the Consolidated vehicles and equipment and transferred all existing field assets (vehicles and equipment) and field personnel to QCOS. Under the terms of the UBS Credit Agreement, QCOS was required to become a guarantor of the UBS Credit Agreement and has pledged its assets as security for its guarantee.

The Company acquired approximately 80 miles of an inactive oil pipeline for approximately $1 million on August 10, 2004. The Company intends to convert this former oil pipeline into a natural gas pipeline. The acquisition was funded with a portion of the remaining net proceeds from the $120 million term loan under the new credit facility with UBS. Additionally, the Company acquired 8 wells and approximately 8,000 acres in the Cherokee Basin on August 6, 2004 for $750,000.

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, $2.6 million in May 2004 and $0.6 million in September 2004.

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 asset 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 asset 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 the Company's 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 asset 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)
Net assets acquired	$ 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 Company 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 asset 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 transition period ended December 31, 2004 and the fiscal years ending May 31, 2004 and 2003 presents the consolidated results of operations as if the Devon asset 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 asset acquisition and the related transactions, please see the Company's Form 8-K filed January 6, 2004.

	Seven Months Ended December 31,	Years Ended May 31,	
	2004	2004	2003
Proforma revenue	$ 26,156,000	$ 45,241,000	$ 26,033,000
Proforma net income (loss)	$ (4,863,000)	$ 2,311,000	$ 67,000
Proforma net income (loss) per share	$ (.34)	$ .17	$ .01

3. Long-Term Debt

Long-term debt consists of the following:

	December 31, 2004
Senior credit facility:	
Revolving loan	$ 15,000,000
Term Loan	119,700,000
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	1,713,000
Convertible debentures – unsecured; interest accrues at 8% per annum	50,000
Total long-term debt	136,463,000
Less – current maturities	1,804,000
Total long term debt, net of current maturities	$ 134,659,000
Subordinated debt (inclusive of accrued interest)	$ 59,325,000

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

2005	$ 1,804,000
2006	1,701,000
2007	1,626,000
2008	1,310,000
2009	16,224,000
Thereafter	173,123,000
	$ 195,788,000

UBS Credit Facility

On July 22, 2004, Quest Cherokee entered into a syndicated credit facility arranged and syndicated by UBS Securities LLC, with UBS AG, Stamford Branch as administrative agent (the "UBS Credit Agreement"). The UBS Credit Agreement originally provided 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 could be used to issue letters of credit and fund future working capital needs and general corporate purposes (the "UBS Revolving Loan"). As of December 31, 2004, Quest Cherokee had approximately $15 million of loans and approximately $5 million in letters of credit issued under the UBS Revolving Loan. Letters of credit issued under the UBS Revolving Loan reduce the amount that can be borrowed there under. The UBS Credit Agreement also contains a $15 million "synthetic" letter of credit facility that matures in December 2008, which provides 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 initially accrued 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 (3.50% for revolving loans and 4.50% 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 4.75% for term loans). In connection with the amendment to the UBS Credit Agreement in February 2005 discussed below, the applicable margin on borrowings under the UBS Credit Agreement was increased by 1% until Quest Cherokee's total leverage ratio is less than 4.0 to 1.0. 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 4.75% 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 (other than the Subordinated Notes) less up to $10 million of unrestricted cash.

The UBS Credit Agreement was initially 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. In connection with the formation of Quest Cherokee Oilfield Service, LLC ("QCOS") on August 16, 2004, QCOS became a guarantor of the UBS Credit Agreement and pledged its assets as security for its guarantee.

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 (which are described below); 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.

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 January 2005, Quest Cherokee determined that it was not in compliance with the leverage and interest coverage ratios in the UBS Credit Agreement for the quarter ended November 30, 2004. On February 22, 2005, Quest Cherokee and the lenders under the UBS Credit Agreement entered into an amendment and waiver pursuant to which the lenders waived all of the existing defaults under the UBS Credit Agreement and the UBS Credit Agreement was amended, among other things, as follows:

- an additional $12 million of Subordinated Notes to ArcLight was permitted;
- the UBS Term Loan was increased by an additional $5 million to a total of $125 million;
- the Company cannot drill any new wells until not less than 200 wells have been connected to the Company's gathering system since January 1, 2005 and gross daily production is at least 43 mmcfe/d for 20 of the last 30 days prior to the date of drilling, after which time the Company may drill up to 150 new wells prior to December 31, 2005 as long as the ending inventory of wells-in-progress as of

the end of any month does not exceed 250;

- the total leverage ratio for any test period may not exceed:

  5.50 to 1.0 for the first quarter of 2005;
  5.00 to 1.0 for the second quarter of 2005;
  4.50 to 1.0 for the third quarter of 2005;
  3.80 to 1.0 for the fourth quarter of 2005;
  3.30 to 1.0 for the first quarter of 2006;
  2.90 to 1.0 for the second quarter of 2006;
  2.50 to 1.0 for the third quarter of 2006; and
  2.50 to 1.0 for the fourth quarter of 2006 and thereafter;

- the minimum asset coverage ratio for any test period may not be less than 1.25 to 1.0;

- the minimum interest coverage ratio for any test period may not be less than:

  2.70 to 1.0 for each quarter for the year ended December 31, 2005; and
  3.50 to 1.0 for each quarter for the year ended December 31, 2006 and thereafter;

- the minimum fixed charge coverage ratio for any test period (starting March 2006) may not be less than:

  1.00 to 1.0 for each of the first three quarters of 2006;
  1.10 to 1.0 for the fourth quarter of 2006;
  1.25 to 1.0 for each quarter for the year ended December 31, 2007; and
  1.50 to 1.0 thereafter;

- capital expenditures for any test period may not exceed:

  $15 million for the first quarter 2005
  $7.25 million for the second quarter 2005
  $9.5 million for the third quarter 2005
  $13.25 million for the fourth quarter 2005
  $10 million for each quarter for the year ended December 31, 2006; and
  the amount of budgeted capital expenditures for 2007 and thereafter; and

- until the later of December 31, 2005 and the date on which Quest Cherokee's total leverage ratio is less than 3.5 to 1.0, the UBS Revolving Loan may only be used for working capital purposes.

Subordinated Promissory Notes

In connection with the Devon asset acquisition, the Company issued a $51 million junior subordinated promissory note from ArcLight (the "Original Note") pursuant to the terms of a note purchase agreement. The Original Note was purchased at par. The Original 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 Original 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.

On February 11, 2005, Quest Cherokee and ArcLight amended and restated the note purchase agreement to provide for the issuance to ArcLight of up to $15 million of additional 15% junior subordinated promissory notes (the "Additional Notes" and together with the Original Notes, the "Subordinated Notes") pursuant to the terms of an amended and restated note purchase agreement. Also on February 11, 2005, Quest Cherokee issued $5 million of Additional Notes to ArcLight (the "Second Issuance").

The Subordinated Notes, together with all accrued and unpaid interest, were originally due on December 22, 2008. In connection with the UBS Credit Agreement, the maturity date of the Subordinated Notes 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.

In the event that Quest Cherokee is dissolved on or before February 11, 2008 (an "Early Liquidation Event"), the holders of the Subordinated Notes 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 Notes and $88.2 million (140% of the original principal amount of the Subordinated Notes).

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

Under the UBS Credit Agreement, no payments may be made on the Subordinated Notes nor may any distributions be made to the members of Quest Cherokee until after the December 31, 2004 reserve report has been delivered to the lenders. After that date, payments may be made with respect to the Subordinated Notes 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.

In connection with the purchase of the Subordinated Notes, 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 was initially to be distributed generally 85% to the holders of the Subordinated Notes and 15% to the holders of the Class B units until the Subordinated Notes have been repaid. Thereafter, the net cash flow of Quest Cherokee was to be distributed generally 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 was to be distributed generally 30% to the holders of the Class A units and 70% to the holders of the Class B units.

As a condition to the Second Issuance, the amended and restated limited liability company agreement was amended to provided that (1) the portion of Quest Cherokee's net cash flow that is required to be used to repay the Subordinated Notes was increased from 85% to 90%, and the portion of the net cash flow distributable to the Company's subsidiaries, as the holders of all of Quest Cherokee's Class B units, was decreased from 15% to 10%, until the Subordinated Notes have been repaid and (2) after the Subordinated Notes have been repaid and ArcLight has received a 30% internal rate of return on its investment in Quest Cherokee, Quest Cherokee's net cash flow will be distributed generally 35% to ArcLight (as the holder of the Class A Units) and 65% to the Company's subsidiaries (as 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.

The February 11, 2005 amended and restated note purchase agreement also provided for Quest Cherokee to issue to ArcLight Additional Notes in the principal amount of $7 million (the "Third Issuance") upon Quest Cherokee obtaining a waiver from the lenders under the UBS Credit Agreement with respect to Quest Cherokee's default under the credit agreement and an amendment to the credit agreement to permit the issuance of Additional Notes to ArcLight. On February 22, 2005, Quest Cherokee obtained the necessary waivers and amendments to the UBS Credit Agreement and closed on the Third Issuance. At the same time, Quest Cherokee borrowed $5 million of additional term loans under the UBS Credit Agreement.

Finally, the amended and restated note purchase agreement provides Quest Cherokee with the option to issue to ArcLight Additional Notes in the principal amount of $3 million (the "Fourth Issuance"). In the event of the Fourth Issuance:

- the interest rate on the Subordinated Notes would increase from 15% to 20%;
- the portion of Quest Cherokee's net cash flow that is required to be used to repay the Subordinated Notes would be further increased from 90% to 95%, and the portion of the net cash flow distributable to the Company's subsidiaries, as the holders of all of Quest Cherokee's Class B units, would be further decreased from 10% to 5%, until the Subordinated Notes have been repaid; and
- after the Subordinated Notes have been repaid and ArcLight has received a 30% internal rate of return on its investment in Quest Cherokee, Quest Cherokee's net cash flow would be distributed 40% to ArcLight (as the holder of the Class A Units) and 60% to the Company's subsidiaries (as the holders of the Class B Units).

It is not currently anticipated that Quest Cherokee will exercise its option to issue any Additional Notes in a Fourth Issuance.

Other Long-Term Indebtedness.

QES has one promissory note with an authorized credit limit of $440,000. The note matures on February 19, 2008, bears interest at the annual rate of 7% per annum, requires monthly payments based upon a 60-month amortization, is secured by equipment and rolling stock, and had a principal balance outstanding on December 31, 2004 of $373,000. The obligation under this note was assumed by Quest Cherokee as part of the restructuring of the Company's operations in connection with the acquisition of natural gas leases and related pipelines and equipment from Devon Energy Production Company, L.P. and Tall Grass Gas Services, LLC in December 2003. Approximately $1.3 million of notes with various financial lenders for equipment and vehicle purchases comprise the remainder.

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.

Convertible Debentures

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. No debentures were converted during the seven-month transition period ended December 31, 2004.

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 December 31, 2004, there were 14,249,694 shares of common stock outstanding. The following transactions were recorded in the Company's financial statements during the seven-month transition period ended December 31, 2004.

1) Issued 17,000 shares of common stock to compensate director for audit committee service.
2) Issued 120,000 shares of common stock for $480,000 in cash.

The following transactions were recorded in the Company's financial statements during the fiscal 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 fiscal 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 December 31, 2004.

Other comprehensive income

The components of other comprehensive loss and related tax effects for the seven-month transition period ended December 31, 2004 and the year ended May 31, 2004 are shown as follows:

	Gross	Tax Effect	Net of Tax
Seven Months Ended December 31, 2004:			
Change in fixed-price contract and other derivative fair value	$ (5,258,000)	$ --	$ (5,258,000)
Reclassification adjustments – contract settlements	4,744,000	--	4,744,000
	$ (514,000)	$ --	$ (514,000)
Year Ended May 31, 2004:			
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 seven-month transition period ended December 31, 2004 and the fiscal year ended May 31, 2004 are as follows:

	Seven Months Ended December 31, 2004	Year Ended May 31, 2004
Current tax expense:		
Federal	$ --	$ --
State	--	--
	--	--
Deferred tax expense:		
Federal	--	(208,000)
State	--	(37,000)
	--	(245,000)
	$ --	$ (245,000)

A reconciliation of income tax at the statutory rate to the Company's effective rate for the seven-month transition period ended December 31, 2004 and the fiscal year ended May 31, 2004 is as follows:

	Seven Months Ended December 31, 2004	Year Ended May 31, 2004
Computation of deferred income tax expense (benefit) at statutory rate	$ (1,872,000)	$ (245,000)
Benefit allocated to minority members of Quest Cherokee	562,000	--
Other	104,000	--
Change in valuation allowance	1,206,000	--
	$ --	$ (245,000)

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

	Seven Months Ended December 31, 2004	Year Ended May 31, 2004
Deferred tax liabilities, non-current:		
Book basis in property and equipment in excess of tax basis, net of accumulated depreciation, depletion and amortization	$ (6,825,000)	$ (2,686,000)
Deferred tax assets, current:		
Hedging contracts expenses per books but deferred for income tax reporting purposes	5,917,000	2,752,000
Net operating loss carryforwards	1,506,000	--
Percentage depletion carryforwards	608,000	--
Other	--	(66,000)
Deferred tax assets	8,031,000	2,686,000
Net deferred tax (liability) asset	1,206,000	--
Less: Valuation allowance	(1,206,000)	--
Total deferred tax (liability) asset	$ --	$ --

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 December 31, 2004, the Company had federal income tax net operating loss (NOL) carryforwards of approximately $3,912,000. 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 in Suite 200 at 5901 N. Western in Oklahoma City, Oklahoma 73118 and the space was rented from Mr. Cash, who is the Chairman, Chief Executive Officer and a director of the Company for the amount of $3,050 monthly.

The Company also owns a building located at 211 West 14th Street in Chanute, Kansas, 66720 that is used as an administrative office. Prior to November 2004, an administrative office for the Company and its subsidiaries was located at 701 East Main Street in Benedict, Kansas 66714. It was 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, President and a director of the Company.

8. Supplemental Cash Flow Information

	Seven Months Ended December 31, 2004	Year Ended May 31, 2004	Year Ended May 31, 2003
Cash paid for interest	$ 4,760,000	$ 3,354,000	$ 515,000
Cash paid for income taxes	$ --	$ --	$ --

Supplementary Information:

During the seven-month transition period ended December 31, 2004, non-cash investing and financing activities are as follows:

1) Issued 17,000 shares of common stock to compensate director for audit committee service.
2) Recorded non-cash additions to net natural gas and oil properties of $126,000 pursuant to SFAS 143.

During the fiscal 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

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 the Company's preliminary investigation, the Company believes that the claims against it are without merit and intends to defend against them vigorously.

STP was 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 was alleging improper operation of a gas gathering system. The plaintiff was seeking unspecified actual and punitive damages as a result of the alleged improper operations by STP. The case was heard by jury trial in September 2004 and the plaintiff was awarded a judgment of approximately $178,000 that has been paid by the Company.

Quest Cherokee, LLC was named as a defendant in a lawsuit (Case No. 04-CV-156-1) filed by plaintiffs Wilbur A. Schwatken, Trustee of the Wilbur A. Schwatken Revocable Trust and Vera D. Schwatken, Trustee of the Vera D. Schwatken Revocable Trust on November 23, 2004 in the District Court of Montgomery County, Kansas. Plaintiff is alleging an oil and gas lease covering approximately 2,245 net acres executed by plaintiff on July 18, 2001 is terminated due to no production being established prior to the expiration date of the primary term of the lease. Plaintiff is seeking actual damages for cost to restore land and unspecified punitive damages. On March 16, 2005, the court granted Quest Cherokee's motion for summary judgment and held that Quest Cherokee's oil and gas lease is valid. The Company believes that the plaintiff is likely to appeal the district court's ruling. Based on information available to date and the Company's investigation into the matter, the Company believes that the claims are without merit and intends to continue to defend against them vigorously.

Quest Cherokee, LLC was named as a defendant in a lawsuit (Case No. 04-C-100-PA) filed by plaintiff Central Natural Resources, Inc. on September 1, 2004 in the District Court of Labette County, Kansas. Central Natural Resources owns the coal underlying several tracts of land in Labette County, Kansas. Quest Cherokee has obtained oil and gas leases from the owners of the oil, gas, and minerals other than coal underlying those lands and has drilled four wells that produce coal bed methane gas on that land. Plaintiff is alleging it is entitled to the coal bed methane gas produced and revenues from these leases and that Quest Cherokee is a trespasser. Plaintiff is seeking quiet title and an equitable accounting on the revenues for the coal bed methane gas produced. The Company contends it has valid leases with the owners of the coal bed methane gas rights. The issue is whether the coal bed methane gas is owned by the owner of the coal rights or by the owners of the gas rights. Quest Cherokee has asserted third party claims against the persons who entered into the gas leases with Quest Cherokee for breach of the warranty of title contained in their leases in the event that the court finds that plaintiff owns the coal bed methane gas. Cross motions for summary judgment are due on May 2, 2005, and oral argument on those motions is scheduled for June 10, 2005. Based on information available to date and the Company's investigation into the matter, the Company believes that the plaintiff's claims are without merit and intends to defend against them vigorously.

Quest Cherokee, LLC, STP Cherokee, Inc. and Bluestem Pipeline, LLC were named as defendants in a lawsuit (Case No. CJ-05-23) filed by plaintiff Davis Operating Company on February 9, 2005 in the District Court of Craig County, Oklahoma. Plaintiff is alleging a breach of contract. Plaintiff is seeking $373,704 as a result of the breach of the contract. The Company believes that the contract in question expired pursuant to its own terms. Therefore, based on information available to date and the Company's investigation into the matter, the Company believes that the claims are without merit and intends to defend against them vigorously.

Quest Resource Corporation, E. Wayne Willhite, and James R. Perkins were named as defendants in a lawsuit (Case No. 04 CV 14) filed by plaintiffs Bill Sweaney and Charles Roye on August 9, 2004 in the district court of Elk County, Kansas. Plaintiffs claim to own a short gas gathering line in Elk County, Kansas. Plaintiffs claim that the Company has used their pipeline to transport gas and, as a result, they are owed compensation for that use. Plaintiffs have not quantified the amount of their alleged damages. Based on information available to date and the Company's investigation into the matter, the Company believes that the claims are without merit and intends to defend against them vigorously.

Quest Cherokee, G. N. Resources, Inc., Alan B. and Sharon L. Hougardy, Gerald L. and Debra A. Callarman, and Tammy L. and Kenneth Allen were named as defendants in a lawsuit (Case No. 2003-CV-8) filed by plaintiff Union Central Life Insurance Company in the district court of Neosho County, Kansas on January 30, 2003. Plaintiff claims to own 1/2 of the oil, gas, and minerals underlying three tracts of land in Neosho County, Kansas. Quest Cherokee obtained oil and gas leases from the owners of that land and has drilled and completed 4 wells on that land. Quest Cherokee and the landowner defendants all deny plaintiff's claim of ownership to 1/2 of the oil and gas. Plaintiff has filed a motion for summary judgment on the issue of its ownership of the 1/2 mineral interest. That motion has been fully briefed and is scheduled for hearing on April 25, 2005. Some discovery has been conducted in the case. Based on information available to date and the Company's investigation into the matter, the Company believes that the claims are without merit and intends to defend against them vigorously.

Bluestem Pipeline has been named as a respondent in four complaints filed before the Kansas Corporation Commission and one complaint before the Oklahoma Corporation Commission. Each of the complaints request that the applicable Commission review and determine whether rates charged by Bluestem Pipeline for gas gathering services on its gas gathering systems in Labette, Chautauqua and Montgomery counties in Kansas or Craig county in Oklahoma, as applicable, are just, reasonable, and non-discriminatory. Discovery is on-going with respect to these complaints. Based on information available to date and the Company's investigation into the matters, the Company believes that the claims are without merit and intends to defend against them vigorously.

Quest Cherokee has received two Notices of Violations from the Kansas Corporation Commission demanding that Quest Cherokee plug a total of 20 abandoned wells on properties leased by Quest Cherokee in Wilson and Labette counties in Kansas. Failure to plug those abandoned wells could result in a recommendation of a fine of $1,000 per well. Based upon information available to date and the Company's investigation into the matter, the Company intends to plug three of those abandoned wells. The Company believes that the Kansas Corporation Commission's claims regarding the remaining abandoned wells on these leases 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. Like other natural gas and oil producers and marketers, the Company's operations are subject to extensive and rapidly changing federal and state environmental regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Therefore it is extremely difficult to reasonably quantify future environmental related expenditures.

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 seven-month transition period ended December 31, 2004 and for the fiscal years ended May 31, 2004 and 2003, dilutive shares do not include outstanding warrants to purchase 1,600,000, 1,600,000 and 898,000 shares, respectively, of common stock at an exercise price of $.001 because the effects were antidilutive.

- For the seven-month transition period ended December 31, 2004 and for the fiscal 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 seven-month transition period ended December 31, 2004 and for the fiscal years ended May 31, 2004 and 2003, dilutive shares do not include the assumed conversion of convertible debt (convertible into 10,000 common shares in the transition period ended December 31, 2004, 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 seven months ended December 31, 2004:			
Net loss	$ (4,863,000)		
Preferred stock dividends	(6,000)		
Basic EPS income available to common shareholders	$ (4,869,000)	14,153,381	$ (0.34)
Effect of dilutive securities:			
None	--	--	
Diluted EPS income available to common shareholders	$ (4,869,000)	14,153,381	$ (0.34)

	Income (Numerator)	Shares (Denominator)	Per Share Amount
For the fiscal 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)
For the fiscal 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 seven-month transition period ended December 31, 2004 and for the fiscal year ended May 31, 2004:

	Seven Months December 31, 2004	Year Ended May 31, 2004
Asset retirement obligation beginning balance	$ 717,000	$ 254,000
Liabilities incurred	129,000	457,000
Liabilities settled	(3,000)	(6,000)
Accretion expense	28,000	12,000
Revisions in estimated cash flows	--	--
Asset retirement obligation ending balance	$ 871,000	$ 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 seven-month transition period ended December 31, 2004 and 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 December 31, 2004, May 31, 2004 and May 31, 2003, the Company's monthly obligation under these leases totaled $408,000, $284,000 and $127,000, respectively.

Additionally, the minimum annual rental commitments as of December 31, 2004 under noncancellable office space leases as follows: 2005 - $117,720; 2006 - $117,720; 2007 - $123,443; 2008 – $127,530 and 2009 - $53,138.

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 95% of total natural gas and oil revenues for the seven-month transition period ended December 31, 2004 and 90% for the fiscal years ended May 31, 2004 and May 31, 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 December 31, 2004 and May 31, 2004 and the methods and assumptions used to estimate their fair value:

	December 31, 2004		May 31, 2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivative assets:				
Interest rate swaps and caps	$ 523,000	$ 523,000	$ --	$ --
Derivative liabilities:				
Fixed-price natural gas swaps	$ (17,675,000)	$ (17,675,000)	$ (18,144,000)	$ (18,144,000)
Fixed-price natural gas collars	$ (4,802,000)	$ (4,802,000)	$ (1,644,000)	$ (1,644,000)
Bank debt	$ (134,700,000)	$ (134,700,000)	$ (103,700,000)	$ (103,700,000)
Subordinated debt (inclusive of accrued interest)	$ (59,325,000)	$ (59,325,000)	$ (54,459,000)	$ (54,459,000)
Other financing agreements	$ (1,763,000)	$ (1,763,000)	$ (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 all derivative instruments as of December 31, 2004 and May 31, 2004 was based upon 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. See Note 17 - Derivatives.

Derivative assets and liabilities reflected as current in the December 31, 2004 and May 31, 2004 balance sheets represent the estimated fair value of fixed-price contract and interest rate swap and cap settlements scheduled to occur over the subsequent twelve-month period based on market prices for natural gas and fluctuations in interest rates 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 and interest rates 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

Natural Gas 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 and floor prices provided in those contracts. For the seven months ended December 31, 2004 and for the years ended May 31, 2004 and 2003, fixed-price contracts hedged approximately 85.0%, 83.0% and 59.0%, respectively, of the Company's natural gas production. As of December 31, 2004, fixed-price contracts are in place to hedge 22.5 Bcf of estimated future natural gas production. Of this total volume, 8.5 Bcf are hedged for 2005 and 14.0 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 December 31, 2004. See "Market Risk."

	Years Ending December 31,				
	2005	2006	2007	2008	Total
	(dollars in thousands, except price data)				
Natural Gas Swaps:					
Contract vols (MMBtu)	5,474,000	5,614,000	-	-	11,088,000
Weighted-avg fixed price per MMBtu (1)	$ 4.69	$ 4.53	-	-	$ 4.61
Fixed-price sales	$ 25,645	$ 25,433	-	-	$ 51,078
Fair value, net	$ (8,579)	$ (9,096)	-	-	$ (17,675)
Natural Gas Collars:					
Contract vols (MMBtu):					
Floor	3,041,000	1,825,000	3,650,000	2,928,000	11,444,000
Ceiling	3,041,000	1,825,000	3,650,000	2,928,000	11,444,000
Weighted-avg fixed price per MMBtu (1):					
Floor	$ 5.18	$ 5.30	$ 4.83	$ 4.50	$ 4.91
Ceiling	$ 6.23	$ 6.35	$ 5.83	$ 5.52	$ 5.94
Fixed-price sales (2)	$ 18,946	$ 11,589	$ 21,279	$ 16,163	$ 67,977
Fair value, net	$ (934)	$ (768)	$ (1,754)	$ (1,346)	$ (4,802)
Total Natural Gas Contracts					
Contract vols (MMBtu)	8,515,000	7,439,000	3,650,000	2,928,000	22,532,000
Weighted-avg fixed price per MMBtu (1)	$ 5.24	$ 4.98	$ 5.83	$ 5.52	$ 5.28
Fixed-price sales (2)	$ 44,591	$ 37,022	$ 21,279	$ 16,163	$ 119,055
Fair value, net	$ (9,513)	$ (9,864)	$ (1,754)	$ (1,346)	$ (22,477)

(1) The prices to be realized for hedged production are expected to vary from the prices shown due to basis.
(2) 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.

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 oil and gas sales in the period for which the underlying production was hedged. For the seven-month transition period ended December 31, 2004 and for the fiscal years ended May 31, 2004 and 2003, oil and gas sales included $4.7 million, $649,000 and $0, respectively, of net losses associated with realized 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 seven months ended December 31, 2004 and for the years ended May 31, 2004 and 2003, other revenue and expense included $105,000, $1.5 million and $1.2 million, respectively, of net losses associated with realized 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.

Interest Rate Hedging Activities

The Company has entered into interest rate swaps and caps designed to hedge the interest rate exposure associated with borrowings under the UBS Credit Agreement. All interest rate swaps and caps have been executed in connection with the Company's interest rate hedging program. The differential between the fixed rate and the floating rate multiplied by the notional amount is the swap gain or loss. This gain or loss is included in interest expense in the period for which the interest rate exposure was hedged.

For interest rate swaps and caps qualifying as cash flow hedges, changes in fair value of the derivative instruments are shown as adjustments to other comprehensive income. For those interest rate swaps and caps not qualifying as cash flow hedges, changes in fair value of the derivative instruments are recognized in change in derivative fair value in the statement of operations. All changes in fair value of the Company's interest rate swaps and caps are reported in results of operations rather than in other comprehensive income because the critical terms of the interest rate swaps and caps do not comply with certain requirements set forth in SFAS 133. The fair value of all interest rate swaps and caps are recorded as assets or liabilities in the balance sheet.

During the seven months ended December 31, 2004, the Company entered into the following interest rate swaps and caps:

Instrument Type	Term	Notional Amount	Fixed Rate / Cap Rate	Floating Rate	Fair Value as of December 31, 2004
Interest Rate Swap	March 2005 – March 2006	$58,250,000 $53,875,000	2.795%	3-month LIBOR	$ 255,000
Interest Rate Cap	March 2006 - Sept. 2007	$98,705,000 $70,174,600	5.000%	3-month LIBOR	$ 268,000

Change in Derivative Fair Value

Change in derivative fair value in the statements of operations for the seven-month transition period ended December 31, 2004 and for the fiscal years ended May 31, 2004 and May 31, 2003 is comprised of the following:

	Seven Months Ended December 31, 2004	Year Ended May 31, 2004	Year Ended May 31, 2003
Change in fair value of derivatives not qualifying as cash flow hedges	$ (269,000)	$ (1,740,000)	$ (4,867,000)
Amortization of derivative fair value gains and losses recognized in earnings prior to actual cash settlements	565,000	888,000	--
Ineffective portion of derivatives qualifying as cash flow hedges	(1,783,000)	(1,161,000)	--
	$ (1,487,000)	$ (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 Natural Gas Hedging Activities, the Company expects that change in derivative fair value in the statement of operations will include a gain of $9.3 million in 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 and interest rate swaps and caps provide for a net settlement due to or from the respective party as discussed previously. The counterparties to the derivative contracts are a financial institution and a major energy corporation. Should a 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 counterparties.

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. Cancellation or termination of an interest rate swap or cap would subject a greater portion of the Company's long-term debt to market interest rates, which, in an inflationary environment, could have an adverse effect on its future net income. In addition, the associated carrying value of the derivative 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:

	December 31, 2004	May 31, 2004
Natural gas and oil properties and related lease equipment:		
Proved	$ 154,427,000	$ 123,161,000
Unproved	16,707,000	24,662,000
	171,134,000	147,823,000
Accumulated depreciation and depletion	(16,069,000)	(8,881,000)
Net capitalized costs	$ 155,065,000	$ 138,942,000

Unproved properties not subject to amortization consisted mainly of leasehold acquired through acquisitions. The Company will continue to evaluate its 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 that have been capitalized are summarized as follows:

	Seven Months Ended December 31,	Years Ended May 31,	
	2004	2004	2003
Acquisition of properties proved and unproved	$ -	$115,069,000	$ 9,716,000
Development costs	23,192,000	11,621,000	7,430,000
	$ 23,192,000	$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 the transition period ended December 31, 2004 and the fiscal years ended May 31, 2004 and 2003. The following table includes revenues and expenses associated directly with the Company's 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 the Company's natural gas and oil operations.

	Seven Months Ended December 31,	Years Ended May 31,	
	2004	2004	2003
Production revenues	$ 24,201,000	$ 28,147,000	$ 8,345,000
Production costs	(5,389,000)	(6,835,000)	(1,923,000)
Depreciation and depletion	(7,187,000)	(6,802,000)	(1,612,000)
	11,625,000	14,510,000	4,810,000
Imputed income tax provision (1)	(4,650,000)	(5,804,000)	(1,924,000)
Results of operation for natural gas/oil producing activity	$ 6,975,000	$ 8,706,000	$ 2,886,000

(1) The imputed income tax provision is hypothetical (at the statutory rate) and determined without regard to the Company's 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
Purchase of reserves-in-place	--	--
Extensions and discoveries	21,281,611	--
Revisions of previous estimates	--	(3,720)
Production	(5,013,911)	(5,551)
Balance, December 31, 2004	149,843,900	47,834
Proved developed reserves:		
Balance, May 31, 2003	14,016,064	43,083
Balance, May 31, 2004	62,558,920	57,105
Balance, December 31, 2004	81,467,220	47,834

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 seven-month transition period ended December 31, 2004 and for the fiscal 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 December 31, and 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.

	Seven Months Ended December 31,	Years Ended May 31,	
	2004	2004	2003
Future production revenues (1)	$ 959,591,000	$ 796,329,000	$ 136,820,000
Future production costs	(274,015,000)	(264,810,000)	(34,975,000)
Future development costs	(74,470,000)	(48,773,000)	(6,273,000)
Future cash flows before income taxes	611,106,000	482,746,000	95,572,000
Future income tax	(160,734,000)	(128,000,000)	(31,267,000)
Future net cash flows	450,372,000	354,746,000	64,305,000
Effect of discounting future annual cash flows at 10%	(154,769,000)	(120,802,000)	(17,237,000)
Standardized measure of discounted net cash flows	$ 295,603,000	$ 233,944,000	$ 47,068,000

(1) The weighted average natural gas and oil wellhead prices used in computing the Company's reserves were $6.30 per mcf and $41.07 per bbl at December 31, 2004, compared to $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:

	Seven Months Ended December 31,	Years Ended May 31,	
	2004	2004	2003
Sales and transfers of natural gas and oil, net of production costs	$ (18,419,000)	$ (21,312,000)	$ (6,422,000)
Net changes in prices and production costs	45,264,000	7,461,000	22,984,000
Acquisitions of natural gas and oil in place – less related production costs	-	217,924,000	36,106,000
Extensions and discoveries, less related production costs	46,686,000	19,956,000	6,675,000
Revisions of previous quantity estimates less related production costs	5,004,000	22,722,000	(3,717,000)
Accretion of discount	4,609,000	3,917,000	2,555,000
Net change in income taxes	(21,485,000)	(63,792,000)	(22,780,000)
Total change in standardized measure of discounted future net cash flows	$ 61,659,000	$ 186,876,000	$ 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 December 31, 2004 and May 31, 2004 and 2003:

	Seven Months Ended December 31,	Years Ended May 31,	
	2004	2004	2003
Standardized measure of discounted future net cash flows	$ 295,603,000	$ 233,944,000	$ 47,068,000
Proved natural gas & oil property net of accumulated depletion	138,358,000	114,280,000	16,694,000
Standardized measure of discounted future net cash flows in excess of net carrying value of proved natural gas & oil properties	$ 157,245,000	$119,664,000	$ 30,374,000

19. Recent Accounting Pronouncements

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. The Company does not expect this statement to have an effect on its reporting as the Company has no financial instruments with these characteristics.

Inventory Costs – an amendment of ARB No. 43

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs - an amendment of ARB No. 43, Chapter 4*. Statement No. 151 requires that certain abnormal costs associated with the manufacturing, freight, and handling costs associated with inventory be charged to current operations in the period in which they are incurred. The financial statements are unaffected by implementation of this new standard.

Revision of SFAS No. 123, Share-Based Payment

In December 2004, the FASB issued a revision of SFAS No. 123, *Share-Based Payment*. The statement establishes standards for the accounting for transactions in which an entity exchanges its equity investments for goods and services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. The statement does not change the accounting guidance for share-based payments with parties other than employees. The statement is effective for the quarter beginning January 1, 2006. The Company does not expect this statement to have an effect on its reporting.

Accounting for Exchanges of Non-monetary Assets-amendment of APB Opinion No. 29

In December 2004, the FASB issued SFAS No. 153, *Exchanges of Non-monetary Assets-amendment of APB Opinion No. 29*. Statement 153 eliminates the exception to fair value for exchanges of similar productive assets and replaces it with a general exception for exchanged transactions that do not have a commercial substance, defined as transactions that are not expected to result in significant changes in the cash flows of the reporting entity. This statement is effective for exchanges of non-monetary assets occurring after June 15, 2005. The Company does not expect this statement to have an effect on its reporting.

20. Subsequent Events

No other material subsequent events have occurred that warrants disclosure since the balance sheet date, other than as disclosed above in Note 3—Long-Term Debt.

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

NONE.

ITEM 8A. CONTROLS AND PROCEDURES

The Company's management, including the Chief Executive Officer and the Chief Financial Officer, evaluated the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that, 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.

As previously reported, during the period covered by this report, the Company identified various accounting errors in its financial reports. These errors primarily relate to the failure to adopt and properly apply certain accounting pronouncements. 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 below, the steps taken by the Company included:

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.

In addition, in March 2005 the Company implemented a new purchase order system that requires a purchase order to be issued by the purchasing manager for all company purchases in excess of $1,000.

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 2005 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's transition period ended December 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 2005 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's transition period ended December 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 2005 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's transition period ended December 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 2005 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's transition period ended December 31, 2004.

ITEM 13. EXHIBITS

Index to Exhibits. Exhibits requiring attachment pursuant to Item 601 of Regulation S-B are listed in the Index to Exhibits beginning on page 25 of this Form 10-KSB that 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 2005 Annual Meeting of Stockholders to be filed with the SEC pursuant to Regulation 14A within 120 days after the end of the Company's transition period ended December 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 6th day of April, 2005.

Quest Resource Corporation

/s/ Jerry D. Cash
Jerry D. Cash
Chief Executive Officer

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	Director and Chief Executive Officer	April 6, 2005
/s/ Douglas L. Lamb Douglas L. Lamb	Director and President	April 6, 2005
/s/ John C. Garrison John C. Garrison	Director	April 6, 2005
/s/ James B. Kite, Jr. James B. Kite, Jr.	Director	April 6, 2005
/s/ David E. Grose David E. Grose	Principal Financial and Accounting Officer	April 6, 2005

INDEX TO EXHIBITS

Exhibit No.	Description
2.1*	Stock Purchase Agreement by and among Perkins Oil Enterprises, Inc. and E. Wayne Willhite Energy, L.L.C, as Sellers, and Ponderosa Gas Pipeline Company, Inc. and Quest Resource Corporation, as Purchasers, dated as of April 1, 2003 (incorporated herein by reference to Exhibit 2.1 to the Company's Quarterly Report on Form 10-QSB filed on April 14, 2003).
2.2*	Purchase and Sale Agreement by and among James R. Perkins Energy, L.L.C., E. Wayne Willhite Energy, L.L.C., and J-W Gas Gathering, L.L.C., as Sellers, and Quest Oil & Gas Corporation, as Purchaser, dated as of April 1, 2003 (incorporated herein by reference to Exhibit 2.2 to the Company's Quarterly Report on Form 10-QSB filed on April 14, 2003).
2.3*	Purchase and Sale Agreement by and between Devon Energy Production Company, L.P., Tall Grass Gas Services, L.L.C., and Quest Resource Corporation, dated as of the 10th day of December, 2003 (incorporated herein by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on January 6, 2004).
2.4*	Assignment Agreement by and between Quest Resource Corporation and Quest Cherokee, LLC, dated as of the 22nd day of December, 2003, assigning the Purchase and Sale Agreement (incorporated herein by reference to Exhibit 2.4 to the Company's Annual Report on Form 10-KSB filed on September 20, 2004).
2.5*	Hold Back Agreement by and between Devon Energy Production Company, L.P. and Quest Cherokee, LLC, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 2.3 to the Company's Current Report on Form 8-K filed on January 6, 2004).
2.6*	Contribution, Conveyance, Assignment and Assumption Agreement by and between Quest Oil & Gas Corporation, Quest Energy Service, Inc., STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service Incorporated, J-W Gas Gathering, L.L.C., Quest Cherokee, LLC and Bluestem Pipeline, LLC, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 2.4 to the Company's Current Report on Form 8-K filed on January 6, 2004).
3.1*	The Company's Article of Incorporation (incorporated herein by reference to the Exhibits to the Company's Registration Statement on Form S-18, Registration No. 2-99737-LA).
3.2*	The Amended and Restated Bylaws of the Company (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on November 19, 2002).
3.3*	The Company's Certificate of Designations, Preferences and Rights of Series A Convertible Preferred Stock (incorporated herein by reference to Exhibit 3.3 to the Company's Annual Report on Form 10-KSB filed on September 20, 2004).
4.1*	Warrant to Purchase 1,600,000 Shares of Quest Resource Corporation common stock issued by Quest Resource Corporation to, and purchased by Wells Fargo Energy Capital, Inc. on November 7, 2002 (incorporated herein by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K filed on November 27, 2002).
4.2*	Warrant Purchase Agreement by and among Quest Resource Corporation and Wells Fargo Energy Capital, Inc., concerning the purchase of the Warrant to Purchase 1,600,000 Shares of Quest Resource Corporation common stock, dated as of November 7, 2002 (incorporated herein by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed on November 27, 2002).
4.3*	Note Purchase Agreement by and between Quest Cherokee, LLC and Cherokee Energy Partners LLC, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on January 6, 2004).

4.4*	First Amendment to Note Purchase Agreement by and between Quest Cherokee, LLC and Cherokee Energy Partners LLC, dated as of July 22, 2004 (incorporated herein by reference to Exhibit 4.7 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
4.5*	Amended and Restated Note Purchase Agreement, by and between, Quest Cherokee, LLC and Cherokee Energy Partners, LLC, dated as of the 11th day of February, 2005 (filed as Exhibit 4.1 to Quest Resource Corporation's Form 8-K filed February 17, 2005 and incorporated herein by reference).
4.6*	Junior Subordinated Promissory Note made by Quest Cherokee, LLC in favor of and to the order of Cherokee Energy Partners LLC, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on January 6, 2004).
4.7*	Amended and Restated Junior Subordinated Promissory Note made by Quest Cherokee, LLC in favour of and to the order of Cherokee Energy Partners LLC, dated as of July 22, 2004 (incorporated herein by reference to Exhibit 4.8 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
4.8**	Junior Subordinated Promissory Note made by Quest Cherokee, LLC in favor of and to the order of Cherokee Energy Partners LLC, dated as of the 11th day of February, 2005.
4.9**	Junior Subordinated Promissory Note made by Quest Cherokee, LLC in favor of and to the order of Cherokee Energy Partners LLC, dated as of the 22nd day of February, 2005.
4.10*	Credit Agreement by and between Quest Cherokee, LLC, Bank One, NA, as administrative agent, and certain financial institutions a party thereto, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on January 6, 2004).
4.11*	Senior Term Second Lien Secured Credit Agreement by and between Quest Cherokee, LLC, Bluestem Pipeline, LLC, Bank One, NA, as agent, and certain lenders a party thereto, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K filed on January 6, 2004).
4.12*	Pledge Agreement by Quest Cherokee, LLC, in favor of Bank One, NA, as collateral agent for the benefit of the revolving lenders under the Credit Agreement and the term lenders under the Senior Term Second Lien Secured Credit Agreement, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed on January 6, 2004).
4.13*	Pledge Agreement by Quest Oil & Gas Corporation, Quest Energy Service, Inc., STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service Incorporated and J-W Gas Gathering, L.L.C., in favor of Bank One, NA, as collateral agent for the benefit of the revolving lenders under the Credit Agreement and the term lenders under the Senior Term Second Lien Secured Credit Agreement, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 4.6 to the Company's Current Report on Form 8-K filed on January 6, 2004).
4.14*	Collateral Agency and Intercreditor Agreement by and between Quest Cherokee, LLC, Bluestem Pipeline, LLC, Quest Oil & Gas Corporation, Quest Energy Service, Inc., STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service Incorporated, J-W Gas Gathering, L.L.C., Cherokee Energy Partners LLC, Bank One, NA, in its capacity as agent under the Credit Agreement, the revolving lenders under the Credit Agreement, Bank One, NA, in its capacity as agent under the Senior Term Second Lien Secured Credit Agreement, the term lenders under the Senior Term Second Lien Secured Credit Agreement, and Bank One, NA, as collateral agent, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 4.7 to the Company's Current Report on Form 8-K filed on January 6, 2004).
4.15*	Guaranty by Bluestem Pipeline, LLC in favor of Bank One, NA, in its capacity as a revolving lender under the Credit Agreement and a term lender under the Senior Term Second Lien Secured

Credit Agreement, and each of the other revolving lenders under the Credit Agreement and term lenders under the Senior Term Second Lien Secured Credit Agreement, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 4.8 to the Company's Current Report on Form 8-K filed on January 6, 2004).

4.16*	Credit Agreement dated as of July 22, 2004 among Quest Cherokee, LLC, the guarantors listed therein, UBS Securities, LLC, as arranger, documentation agent and syndication agent, UBS AG, Stamford Branch, as issuing bank, LC Facility issuing bank, administrative agent and collateral agent, UBS Loan Finance LLC as swingline lender, and certain financial institutions a party thereto (incorporated herein by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
4.17**	Amendment No. 1 to Credit Agreement, by and between, Quest Cherokee, LLC, the subsidiary guarantors and the various lenders party to the UBS Amended Credit Agreement, UBS Securities LLC, as the lead arranger, book manager, documentation agent and syndication agent, UBS AG, Stamford Branch, as issuing bank, the L/C Facility issuing bank, the administrative agent for the lenders and collateral agent for the secured parties, and UBS Loan Finance LLC, as swing line lender, dated as of the 19th day of November, 2004.
4.18*	Amendment No. 2 and Waiver to Credit Agreement, by and between, Quest Cherokee, LLC, the subsidiary guarantors and the various lenders party to the UBS Amended Credit Agreement, UBS Securities LLC, as the lead arranger, book manager, documentation agent and syndication agent, UBS AG, Stamford Branch, as issuing bank, the L/C Facility issuing bank, the administrative agent for the lenders and collateral agent for the secured parties, and UBS Loan Finance LLC, as swing line lender, dated as of the 22nd day of February, 2005 (incorporated herein by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-QSB filed February 23. 2005).
4.19*	Loan Transfer Agreement dated as of July 22, 2004 among Quest Cherokee, LLC, Bluestem Pipeline, LLC, Quest Oil & Gas Corporation, Quest Energy Service, Inc, STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service, Incorporated, J-W Gas Gathering, LLC, Cherokee, Energy Partners, LLC, Bank One, NA, as administrative agent, issuing bank and collateral agent, and UBS, AG, Standford Branch, as administrative agent and collateral agent (incorporated herein by reference to Exhibit 4.2 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
4.20*	Security Agreement dated as of July 22, 2004 by Quest Cherokee, LLC and the guarantors listed on the signature page thereof and UBS AG, Stamford Branch, as collateral agent (incorporated herein by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
4.21*	Assignment of and Amendment to Mortgage dated as of July 22, 2004 by Bank One, NA, as collateral agent for the existing lenders, to UBS AG, Stamford Branch, as collateral agent for secured parties, and Quest Cherokee, LLC (incorporated herein by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
4.22*	Amended and Restated Mortgage, Deed of Trust, Security Agreement, Financing Statement and Assignment of Production from Quest Cherokee, LLC to UBS AG, Stamford Branch, as Collateral Agent for secured parties, dated July 22, 2004 (incorporated herein by reference to Exhibit 4.5 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
4.23*	Assignment, Assumption and Consent Agreement dated as of July 22, 2004 between Quest Cherokee, LLC, UBS AG, Bank One, NA and JP Morgan Chase Bank (incorporated herein by reference to Exhibit 4.6 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
10.1*	Voting Agreement for Shares of Stock of Quest Resource Corporation by and among Quest Resource Corporation, Douglas L. Lamb and Jerry D. Cash, dated as of November 7, 2002 (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 19, 2002).
10.2*	Consent of Transferee of Shares of Quest Resource Corporation, Boothbay Royalty Company, dated as of November 7, 2002, to the Voting Agreement for Shares of Stock of Quest Resource Corporation by and among Quest Resource Corporation, Douglas L. Lamb and Jerry D. Cash,

dated as of November 7, 2002 (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on November 19, 2002).

10.3*	Consent of Transferee of Shares of Quest Resource Corporation, Southwind Resource, Inc., dated as of November 7, 2002, to the Voting Agreement for Shares of Stock of Quest Resource Corporation by and among Quest Resource Corporation, Douglas L. Lamb and Jerry D. Cash, dated as of November 7, 2002 (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on November 19, 2002).
10.4*	Consent of Transferee of Shares of Quest Resource Corporation, Shiloh Oil Corporation, dated as of April 9, 2003, to the Voting Agreement for Shares of Stock of Quest Resource Corporation by and among Quest Resource Corporation, Douglas L. Lamb and Jerry D. Cash, dated as of November 8, 2002 (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-QSB filed on April 14, 2003).
10.5*	Employment Agreement dated as of November 7, 2002 between Quest Resource Corporation and Jerry Cash (incorporated herein by reference to Exhibit 10.5 to the Company's Annual Report on Form 10-KSB filed on August 29, 2003).
10.6*	Amendment No. 1 dated as of September 22, 2004 to Employment Agreement between the Company and Jerry Cash (incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-QSB filed on February 24, 2005)
10.7*	Employment Agreement dated as of November 7, 2002 between Quest Resource Corporation and Douglas Lamb (incorporated herein by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-KSB filed on August 29, 2003).
10.8*	Amendment No. 1 dated as of September 22, 2004 to Employment Agreement between the Company and Douglas Lamb (incorporated herein by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-QSB filed on February 24, 2005).
10.9*	Audit Committee Share Agreement as of June 6, 2003, between Quest Resource Corporation and John Garrison (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-QSB filed October 15, 2004).
10.10*	Membership Interest Purchase Agreement by and between Quest Cherokee, LLC, Quest Oil & Gas Corporation, Quest Energy Service, Inc., STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service Incorporated, J-W Gas Gathering, L.L.C., and Cherokee Energy Partners LLC, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 6, 2004).
10.11*	Amended and Restated Limited Liability Company Agreement of Quest Cherokee, LLC, by and among Cherokee Energy Partners LLC, Quest Oil & Gas Corporation, Quest Energy Service, Inc., STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service Incorporated and J-W Gas Gathering, L.L.C., dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 6, 2004).
10.12*	Amendment dated February 11, 2005 to the Amended and Restated Limited Liability Company Agreement of Quest Cherokee, LLC, by and among Cherokee Energy Partners LLC, Quest Oil & Gas Corporation, Quest Energy Service, Inc., STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service Incorporated and J-W Gas Gathering, L.L.C., dated as of the 22nd day of December, 2003 (Filed as Exhibit 10.1 to Quest Resource Corporation's Form 8-K filed February 17, 2005 and incorporated herein by reference).
10.13*	Pledge Agreement by Quest Oil & Gas Corporation, Quest Energy Service, Inc., STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service Incorporated and J-W Gas Gathering, L.L.C., in favor of Cherokee Energy Partners LLC, dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on January 6, 2004).
10.14*	Guaranty by Quest Resource Corporation in favor of Cherokee Energy Partners LLC, dated as of

the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on January 6, 2004).

10.15*	Operating and Management Agreement by and between Quest Cherokee, LLC and Quest Energy Service, Inc., dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on January 6, 2004).
10.16*	Non-Competition Agreement by and between by and between Quest Resource Corporation, Quest Cherokee, LLC, Cherokee Energy Partners LLC, Quest Oil & Gas Corporation, Quest Energy Service, Inc., STP Cherokee, Inc., Ponderosa Gas Pipeline Company, Inc., Producers Service Incorporated and J-W Gas Gathering, L.L.C., dated as of the 22nd day of December, 2003 (incorporated herein by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on January 6, 2004).
10.17*	Interest Rate Swap Transaction Agreements between the Quest Cherokee L.L.C. and UBS AG London Branch dated September 21, 2004 (incorporated herein by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-QSB filed on February 24, 2005).
10.18*	Interest Rate Cap Transaction Agreements between the Quest Cherokee L.L.C. and UBS AG London Branch dated September 21, 2004 (incorporated herein by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-QSB filed on February 24, 2005).
10.19**	Summary of executive officer compensation arrangements
21.1**	List of Subsidiaries.
23.1**	Consent of Cawley and Gillespie & Associates, Inc.
23.2**	Consent of McCune Engineering.
23.3***	Consent of Murrell, Hall, McIntosh & Co., PLLP
31.1***	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2***	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1***	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2***	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1**	Risk Factors.

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*	Incorporated by reference.
**	Previously filed
***	Filed herewith.

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

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Common Stock
Traded in
over-the-counter market

Stock Transfer Agent
Securities Transfer Corporation
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Corporate Headquarters
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