BETA OIL & GAS INC
Form 10-K/A
April 20, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K/A

Amendment No.1

ý	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the Year Ended December 31, 2003
	or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the Transition Period From to

Commission File Number: 000-25717

BETA OIL & GAS, INC.

(Exact name of registrant as specified in its charter)

Nevada	**86-0876964**
(State of Incorporation)	(I.R.S. Employer Identification No.)
6100 S. Yale, Suite 300, Tulsa, OK	**74136**
(Address of principal executive offices)	(Zip Code)

(918) 495-1011
(Registrant s telephone number, including area code)

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

Securities registered pursuant to Section 12(g) of the Act: **Common Stock, par value $.001 per share**
(Title of Each Class)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). o Yes ý No

The aggregate market value of such common stock held by non-affiliates was approximately $15,052,365 based on the reported closing sales price of $1.32 on the Nasdaq National Market on June 30, 2003.

Check if disclosure of delinquent filers in response to Item 405 of Regulation S-K is not contained within 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-K or any amendment to this Form 10-K. o

As of March 16, 2004, 12,429,307 shares of the registrant s common stock were outstanding.

Certain sections of the registrant s proxy statement for the 2004 annual meeting of stockholders are incorporated by reference into Part III. Certain sections of amendment no. 3 to the registrant's preliminary proxy statement filed on March 17, 2004 are incorporated by reference into Part I.

Exhibit index follows page F-35.

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GLOSSARY OF TERMS

We are in the business of exploring for and producing oil and natural gas. Oil and gas exploration is a specialized industry. Many of the terms used to describe our business are unique to the oil and gas industry. We present the following glossary to clarify certain of these terms you may encounter while reading this Form 10-K.

Acquisition costs of properties means the costs incurred to obtain rights to production of oil and gas. These costs include the costs of acquiring oil and gas leases and other interests. These costs include lease costs, finder s fees, brokerage fees, title costs, legal costs, recording costs, options to purchase or lease interests and any other costs associated with the acquisition of an interest in current or possible production.

Area of mutual interest or AMI means, generally, an agreed upon area of land, varying in size, included and described in an oil and gas exploration and exploitation agreement which participants agree will be subject to rights of first refusal as among themselves, such that any participant acquiring any minerals, royalty, overriding royalty, oil and gas leasehold estates or similar interests in the designated area, is obligated to offer the other participants the opportunity to purchase their agreed upon percentage share of the interest so acquired on the same basis and cost as purchased by the acquiring participant. If the other participants, after a specific time period, elect not to acquire their pro-rata share, the acquiring participant is typically then free to retain or sell such interests.

Back-in interests also referred to as a carried interest, involve the transfer of interest in a property, with provision to the transferor to receive a reversionary interest in the property after the occurrence of certain events.

Bbl means barrel, 42 U.S. gallons liquid volume, used in this annual report in reference to crude oil or other liquid hydrocarbons.

Bcf means billion cubic feet, used in this annual report in reference to gaseous hydrocarbons.

Bcfe means billions of cubic feet of gas equivalent, determined using the ratio of six thousand cubic feet of gas to one barrel of oil, condensate or gas liquids.

Casing point means the point in time at which an election is made by participants in a well whether to proceed with an attempt to complete the well as a producer or to plug and abandon the well as a non-commercial dry hole. The election is generally made after a well has been drilled to its objective depth and an evaluation has been made from drill cutting samples, well logs, cores, drill stem tests and other methods. If an affirmative election is made to complete the well for production, production casing is then generally cemented in the hole and completion operations are then commenced.

Development costs are costs incurred to drill, equip, or obtain access to proved reserves. They include costs of drilling and equipment necessary to get products to the point of sale and may entail on-site processing.

Exploration costs are costs incurred, either before or after the acquisition of a property, to identify areas that may have potential reserves, to examine specific areas considered to have potential reserves, to drill test wells, and drill exploratory wells. Exploratory wells are wells drilled in unproven areas. The identification of properties and examination of specific areas will typically include geological and geophysical costs, also referred to as G&G, which include topological studies, geographical and geophysical studies, and costs to obtain access to properties under study. Depreciation of support equipment, and the costs of carrying unproved acreage, delay rentals, ad valorem property taxes, title defense costs, and lease or land record maintenance are also classified as exploratory costs.

Farmout involves an entity s assignment of all or a part of its interest in or lease of a property in exchange for consideration such as a royalty.

Future net revenue, before income taxes means an estimate of future net revenue from a property, based on the production of the proven reserves of oil and natural gas believed to be recoverable at a specified date, after deducting production and ad valorem taxes, future capital costs and operating expenses, before deducting income taxes. Future net revenue, before income taxes, should not be construed as being the fair market value of the property.

Future net revenue, net of income taxes means an estimate of future net revenue from a property, based on the proven reserves of oil and natural gas believed to be recoverable at a specified date, after deducting production and ad valorem taxes, future capital costs and operating expenses, net of income taxes. Future net revenues, net of income taxes, should not be construed as being the fair market value of the property.

Gross oil or gas well or **gross** acre is a well or acre in which an owner has a working interest.

Mcf means thousand cubic feet, used in this annual report to refer to gaseous hydrocarbons.

Mcfe means thousands of cubic feet of gas equivalent, determined using the ratio of six thousand cubic feet of gas to one barrel of oil, condensate or gas liquids.

MMcf means million cubic feet, used in this annual report to refer to gaseous hydrocarbons.

MMbtu means million British thermal units, used in this annual report to refer to the energy content associated with natural gas and crude oil**.**

MBbl means thousand barrels, used in this annual report to refer to crude oil or other liquid hydrocarbons.

Net oil and gas wells or **net** acres are determined by multiplying **gross** wells or acres by the owner s working interest percentage in such wells or acres.

Oil and gas lease **or** **lease** means an agreement between a mineral owner, the lessor, and a lessee which conveys the right to the lessee to explore for and produce oil and gas from the leased lands. Oil and gas leases usually have a primary term during which the lessee must establish production of oil and or gas. If production is established within the primary term, the term of the lease generally continues in effect so long as production occurs on the lease. Leases generally provide for a royalty to be paid to the lessor from the gross proceeds from the sale of production.

Overpressured reservoir is a reservoir subject to abnormally high pressure as a result of certain types of subsurface conditions.

Present value of future net revenue, before income taxes means future net revenue, before income taxes, discounted at an annual rate of 10% to determine the present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties.

Present value of future net revenue, net of income taxes means future net revenue, net of income taxes discounted at an annual rate of 10% to determine their present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Also known as the Standardized Measure of Discounted Future Net Cash Flows if SEC pricing assumptions are used.

Production costs means operating expenses and severance and ad valorem taxes on oil and gas production.

Prospect means a location where both geological and economical conditions favor drilling a well.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic recovery by production is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can reasonably be judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Proved developed oil and gas reserves are those proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas reserves expected to be obtained through the application of fluid injection or other improved secondary or tertiary recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed recovery program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are those proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves attributable to any acreage do not include production for which an application of fluid injection or other improved recovery technique is required or contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Reserve target see **Prospect** .

Royalty interest is a right to oil, gas, or other minerals that is not burdened by the costs to develop or operate the related property.

Seismic option generally means an agreement in which the mineral owner grants the right to acquire seismic data on the subject lands and grants an option to acquire an oil and gas lease on the lands at a predetermined price.

Trend means a geographical area along which a petroleum pay occurs (fairway).

Working interest or **WI** is an interest in an oil and gas property that is burdened with the costs of development and operation of the property.

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

Included in this report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this Form 10-K which address activities, events or developments, which we expect or anticipate, will or may occur in the future are forward-looking statements. The words believes, intends, expects, anticipates, projects, estimates, predicts and similar expressions are also intende identify forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations reflected in such forward-looking statements will prove to have been correct.

All forward-looking statements contained in this section are based on assumptions believed to be reasonable.

These forward-looking statements include statements regarding:

Estimates of proved reserve quantities and net present values of those reserves

Reserve potential

Business strategy

Capital expenditures amount and types

Expansion and growth of our business and operations

Expansion and development trends of the oil and gas industry

Production of oil and gas reserves

Exploration prospects

Wells to be drilled, and drilling results

Operating results and working capital

The proposed Petrohawk transaction described under PART I, Item 1. Business and Item 2. Properties General, Petrohawk Transaction

We can give no assurance that our expectations and assumptions will prove to be correct. The Petrohawk transaction is subject to approval by our stockholders at a special meeting which is expected to be held at the end of April or early May, 2004. Reserve estimates of oil and gas properties are generally different from the quantities of oil and natural gas that are ultimately recovered or found. This is particularly true for estimates applied to exploratory prospects and new production. Additionally, any forward-looking statements are subject to various known and unknown risks, uncertainties and contingencies, many of which are beyond our control. Such things may cause actual results, performance, achievements or expectations to differ materially from what we anticipated.

Factors that may affect such forward-looking statements include, but are not limited to:

Our ability to generate additional capital to complete our planned drilling and exploration activities

Risks inherent in oil and gas acquisitions, exploration, drilling, development and production

Oil and natural gas prices

Competition from other oil and gas companies

Shortages of equipment, services and supplies

General economic, market or business conditions

Economic, market or business conditions in the oil and gas industry and in the energy business generally

Government regulation

Environmental matters

Financial condition and operating performance of the other companies participating in the exploration, development and production of oil and gas ventures that we are involved in

Our failure to consummate the Petrohawk transaction

In addition, since some of our prospects are currently operated by third parties, we may not be in a position to control costs, safety and timeliness of work as well as other critical factors affecting a producing well or exploration and development activities.

PART I

Item 1. Business and Item 2. Properties

GENERAL

We are an independent oil and gas company engaged in the exploration, exploitation, development, production and acquisition of natural gas and crude oil. We are a Nevada corporation incorporated in June 1997. Our operations are currently focused on the exploration and development of oil and gas producing trends situated in Oklahoma, Texas, Louisiana and Kansas. Our Australian drilling concession expired in 2003.

At December 31, 2003, we owned interests in approximately 218 gross (181 net) producing wells, in the Mid-Continent, Texas and Louisiana regions and participated in the drilling and completion of 28 gross (7.0 net) wells during the year. Additionally, we own interests in 57,099 net acres in Kansas, Louisiana, Oklahoma, Texas, and Offshore Louisiana State and Federal Waters.

Total proved reserve volumes at December 31, 2003 were 22.4 Bcf of natural gas and 1,307.5 MBbl of oil, or 30.2 Bcfe of natural gas compared to December 31, 2002 proved reserves of 14.7 Bcf of natural gas and 608.6 MBbl of oil or 18.3 Bcfe of natural gas. Total 2003 proved reserves increased approximately 11.9 Bcfe, or 65%, from 2002 primarily due to: 1.) extensions or discoveries of approximately 7.5 Bcfe, 2.) reserve revisions of approximately 5.5 Bcfe due to performance and 3.) higher 2003 year end natural gas and crude oil prices compared to year end 2002 resulting in an increase of approximately 1.5 Bcfe. Average net daily production for 2003 was 7.2 MMcfe, down 12% from 2002 levels. At year-end 2003, the average net daily production was approximately 7.8 MMcfe, compared to 7.5 MMcfe from year end 2002 levels, up 4 percent.

At December 31, 2003, approximately 25.4 Bcfe of natural gas, or 84%, of our total proved reserves were classified as proved developed and approximately 4.7 Bcfe, or 16%, of our total proved reserves were classified as proved undeveloped reserves. As of year-end 2003, the proved undeveloped reserves represented approximately 25% of the total proved oil reserves and approximately 12% of the total proved natural gas reserves. Approximately 30% of the increase in our total reserves from year-end 2002 to year-end 2003 was classified as proved undeveloped reserves. These additions were mostly the result of our workover and drilling programs supported by detailed technical studies in our key areas located in Central Oklahoma (WEHLU), South Central Kansas and South Louisiana. We expect to make approximately $3.6 million in capital expenditures to develop approximately 3.7 Bcfe, or 78%, of our proved undeveloped reserves in 2004. We expect to make approximately $1.3 million in capital expenditures to develop the balance of approximately 1.0 Bcfe, or 22%, of our proved undeveloped reserves in 2005.

Petrohawk Transaction

On December 12, 2003, we entered into a securities purchase agreement (which we generally refer to as the Petrohawk purchase agreement) with Petrohawk Energy, LLC (Petrohawk) pursuant to which we have agreed to issue to Petrohawk for an aggregate of $60,000,000 in cash:

15,151,515 shares of our common stock;

five year warrants to purchase up to an additional 10,000,000 shares of our common stock at an exercise price of $1.65 per share; and

a convertible promissory note in the face amount of $35,000,000 which will be convertible after two years into shares of our common stock at a conversion price of $2.00 per share.

Because issuance of the shares of common stock to Petrohawk in connection with this transaction will result in a change of control of Beta, we are required by the rules of The Nasdaq Stock Market to obtain stockholder approval of the issuance of the shares. A special meeting of our stockholders is expected to be called at the end of April or early May 2004.

The transactions contemplated by the purchase agreement are required to be consummated at a closing that we expect to occur immediately following the approval of the proposal by our stockholders. Holders of approximately 28% of our outstanding common stock have entered into an agreement with Petrohawk in which they commited to vote their shares in favor of the transaction.

Assuming that the transaction is approved by our stockholders and is consummated, the proceeds from the sale of the securities will be added to our working capital and be available for the acquisition, development and exploration of oil and gas properties. A portion of these proceeds is expected to be used to pay off all of our existing long-term bank debt. Under the terms of the Petrohawk purchase agreement, all of our directors except Robert C. Stone, Jr. will resign and six persons designated by Petrohawk will be appointed as new directors. New management will also be appointed and it is anticipated that our headquarters will be moved to the Houston, Texas area.

A more complete discussion of the Petrohawk transaction is contained in the section captioned Proposal No. 1: The Petrohawk Transaction in our preliminary proxy statement which we filed on March 17, 2004. After the completion of the SEC review of our preliminary proxy statement, a definitive proxy statement will be filed with the SEC and is expected to be first sent to our stockholders at the end of March or beginning of April, 2004.

Much of the discussion in this report about our future business, operations and activities is subject to the effects of the Petrohawk transaction if and when it is consummated.

RISK FACTORS

The following risks relate specifically to the conduct of our business. You should also refer to the information under the heading Forward Looking Statements on page 5. These risk factors pertain to our business assuming that the Petrohawk transaction is not consummated. For a discussion of the risk factors relevant to the Petrohawk transaction, you should refer to the section captioned Proposal No. 1 The Petrohawk Transaction Certain Risks Associated with the Proposed Petrohawk Transaction in our preliminary proxy statement which was filed with the SEC on March 17, 2004. This section is incorporated into this report by reference. After the completion of the SEC review of our preliminary proxy statement, a definitive proxy statement will be filed with the SEC and is expected to be first sent to our stockholders at the end of March or beginning of April, 2004.

We have a limited operating history and our developed property interests have incurred operating losses since inception.

We were incorporated in June 1997. We have a limited operating history and are subject to the associated risks. Since our inception, we have incurred operating losses every year except for 2000 and 2003. As of December 31, 2003, we had an accumulated deficit of $22.6 million. If we are unable to generate positive cash flow from our oil and gas operations, we may continue to incur losses. Our ability to achieve and maintain profitability is uncertain.

We are reliant on the skill, ability and decisions of third party operators to a significant extent.

We operate 43% of the producing wells in which we own a working interest and we are a non-operating working interest owner in the remaining 57%**.** With respect to the latter, we have entered into joint operating agreements with third party operators for the conduct and supervision of drilling, completion and production operations of those wells and for the operation of those properties. The success of the drilling, development and production of the oil and gas properties in which we have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to

- make decisions,
- perform their services,
- discharge their obligations,

deal with regulatory agencies, and

comply with laws, rules and regulations affecting the properties in which we have an interest, including environmental laws and regulations

in a proper manner could result in material adverse consequences to our interest in any affected properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us, which could negatively affect our results of operations.

We have not paid, and do not anticipate paying, any dividends on our common stock in the foreseeable future.

We have never paid any cash dividends on our common stock. We do not expect to declare or pay any cash or other dividends in the foreseeable future on our common stock. Holders of our preferred stock are entitled to receive cumulative dividends at the annual rate of $.74 per share when and as declared by our board of directors. No dividends may be paid on our common stock unless all cumulative dividends due on the preferred stock have been declared and paid. We may also enter into credit agreements or other borrowing arrangements, which may restrict our ability to declare dividends on our common stock.

Various factors, including fluctuations in oil and gas prices, economic conditions, environmental and other regulations, could have a material adverse effect on our financial condition and results of operations and may cause considerable volatility in the market price of our common stock.

The market value of our common stock may vary significantly in response to changes in our quarterly results of operations. We expect to experience substantial fluctuations in oil and gas prices due to changes in the supply of and demand for oil and gas, which may be caused by

- weather conditions,
- political conditions in the Middle East and other regions,
- domestic and foreign reserves and supply of oil and gas,
- the price and availability of alternative fuels,
- the level of consumer demand, or
- general economic and market conditions.

In addition, our revenues will be affected by the success or failure of the efforts to drill exploratory wells in the unproven prospects in which we have an interest, the availability of a ready market for the oil and gas production from the wells in which we have an interest and the proximity of such well sites to pipelines and production facilities. Drilling, completion and other costs and expenses will be affected by various market factors over which neither we nor our third party operators may have any control. Due to the uncertainty of our revenues, expenses and profits or losses, the market price of our stock may be volatile in the future.

Our future capital expenditures could exceed those amounts budgeted and could exceed our future funds available for those expenditures.

We project our 2004 capital expenditures to be approximately $5 million and expect our cash flow from operations and funds received from internally-generated prospects to fund those expenditures. Our planned capital expenditures and/or administrative expenses could exceed those amounts budgeted and could exceed the available cash sourced for those expenditures. While our projected cash expenditures may be as forecasted, cash flow from operations could be unfavorably impacted by lower than projected natural gas and crude oil prices and/or lower than projected production rates. Additionally, lower natural gas and crude oil prices could adversely impact our ability to raise any funds from the sale of prospects. To the extent that the funds available from operations and prospect sales are insufficient to fund our activity, it may be necessary to raise additional funds through equity or debt financing. Any equity financing could result in dilution to our then-existing shareholders. Sources of debt financing may result in higher interest expense, further security interests in our assets, other equity interest to our lenders and similar developments. Any financing, if available, may be on terms unfavorable to us. If adequate funds are not obtained, we may be required to reduce or curtail operations. We anticipate that our existing capital resources will be adequate to satisfy our operating expenses and capital requirements for 2004.

Our hedging activities could result in losses.

We have previously engaged in oil and gas hedging activities and intend to continue to consider various hedging arrangements to realize commodity prices that we consider protective or favorable. See **Item 7A. Quantitative and Qualitative Disclosure About Market Risk** for a discussion of our current hedging activity. As with the natural gas contracts, the crude oil contracts are costless and no net premium is received in cash or as a favorable rate. The impact of changes in the market price for oil and gas on the average oil and gas prices received by us may be reduced from time to time based on the level of our hedging activities. These hedging arrangements may limit our potential gain if the market prices for oil and gas were to rise substantially over the ceiling price established by the hedge. In addition, our hedging arrangements expose us to the risk of financial loss in certain circumstances, including instances in which (1) production is less than expected or (2) the counterparties to our hedging arrangements fail to honor their financial commitments.

We have substantial long-term indebtedness.

Under our current credit facility, we have a total indebtedness outstanding of approximately $13.3 million with a current total borrowing capacity of $13.8 million, which is subject to an automatic monthly reduction of $88,000, which commenced on July 31, 2003. Historically due to commodity price volatility and a reduction in our proved developed reserves, our borrowing capacity has not significantly increased and has not been a material source of funds. We are currently required to pay interest only on the amount outstanding on a monthly basis. Should our proved developed reserves not materially increase and/or pricing substantially decrease before the next re-determination date, our current borrowing base may be reduced below the amount currently borrowed and outstanding. If this event occurs we would be obligated to pay down the outstanding amount to the re-determined borrowing capacity. We would rely on cash flow from operations and funds generated from prospect sales to make this pay down. Since the facility is secured by our producing oil and gas properties, should we be unable to pay down the obligation at re-determination or maturity, we could sustain a loss on our investment as a result of foreclosure by the lender on the interests in these properties. The next re-determination date is April 2004 and the credit facility matures in April 2005.

Our oil and gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and gas. Although we or the third party operator of the properties, in which we have an interest, may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, production of oil and gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities,

blowouts, fires, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment,

unavailability of materials and equipment,

engineering and construction delays,

unanticipated transportation costs and delays,

unfavorable weather conditions, hazards resulting from unusual or unexpected geological or environmental conditions,

environmental regulations and requirements,

accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment,

changes in laws and regulations, including laws and regulations applicable to oil and gas activities or markets for the oil and gas produced,

fluctuations in supply and demand for oil and gas causing variations of the prices we receive for our oil and gas production, the internal and political decisions of OPEC and oil and gas producing nations and their impact upon oil and gas prices.

As a result of these risks, expenditures, quantities and rates of production, revenues and cash operating costs may be materially adversely affected and may differ materially from those anticipated by us.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

If the proposed Petrohawk transaction is not consummated, our future performance will be substantially dependent on the performance of our executive officers and key employees. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows. The pendency of the Petrohawk transaction may make it difficult to retain all of our key employees.

Governmental and environmental regulations could adversely affect our business.

Our business is subject to federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and gas and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

Our operations are also subject to complex environmental laws and regulations adopted by the various jurisdictions in which we have oil and gas operations. We could incur liability to governments or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could potentially discharge these materials into the environment in any of the following ways:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering and explosions.

Because the requirements imposed by laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, because we acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage caused by the former operators.

Our business is highly competitive.

The oil and gas industry is highly competitive in many respects, including identification of attractive oil and gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and gas companies and other independent operators with greater financial resources and, in some cases, with more expertise. Many other oil and gas companies in the industry have financial resources, personnel and facilities substantially greater than ours and there can be no assurance that we will be able to compete effectively with these larger entities.

Our ability to produce our proved reserves is subject to a number of risks and uncertainties.

A portion of our oil and gas reserves is or may become, with future successful drilling of our prospects, proved undeveloped reserves. Successful development and production of such reserves, although categorized as proved , cannot be assured. Additional drilling will be necessary in future years both to maintain production levels and to define the extent and recoverability of existing proved undeveloped reserves. There is no assurance that our present oil and gas wells will continue to produce at current or anticipated rates of production, that development drilling will be successful, that production of oil and gas will commence when expected, that there will be favorable markets for oil and gas which may be produced in the future or that production rates achieved in early periods can be maintained.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or failure. Under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses which may be sustained in connection with all oil and gas activities.

We have purchased and are maintaining a general and excess liability policy with a total limit on claims of $11,000,000 and a workers compensation policy to provide added insurance if the coverage provided by an operators policy is inadequate to cover our losses. Our policies, and the policies maintained by our third party operators, which have limits ranging from $10,000,000 to $25,000,000 depending on the type of occurrence, generally cover:

personal injury,

bodily injury,

third party property damage,

medical expenses,

legal defense costs,

pollution in some cases,

well blowouts in some cases and

workers compensation

A loss in connection with our oil and gas properties could have a materially adverse effect on our financial position and results of operation to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.

Our future performance depends upon our ability to find or acquire additional oil and gas reserves that are economically recoverable.

In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and gas production and lower revenues and cash flow from operations. We intend to increase our reserves after taking production into account through exploitation, development and exploration on our existing oil and gas properties as well as on newly acquired properties. We may not be able to replace reserves from such activities at acceptable costs. Low prices of oil and gas may further limit the kinds of reserves that can economically be developed. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

We are continually identifying and evaluating opportunities to acquire oil and gas properties, including acquisitions that would be significantly larger than those consummated to date by us. We cannot assure you that we will successfully consummate any acquisition, that we will be able to acquire producing oil and gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

Estimates of oil and gas reserves depend on various assumptions and, to the extent that the actual facts prove to be materially different from these assumptions, the quantity and value of our future oil and gas production could differ materially from these estimates.

The proved oil and gas reserve information included in this document represents estimates based on rigorous technical evaluations and extrapolations of well information such as flow rates and reservoir pressure declines, and requires significant judgments and assumptions in the evaluation of available geological, geophysical, engineering, production and economic data for each property. The requirements of the SEC provide that proved oil and gas reserves are limited to those estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. We believe that the estimates of our proved reserves meet this reasonable certainty test. However, it should be understood that petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions (including certain assumptions required by the SEC) including:

historical production from the area compared with production from other comparable producing areas;

the assumed effects of regulations by governmental agencies;

assumptions concerning future oil and gas prices; and

assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves:

the quantities of oil and gas that are ultimately recovered;

the timing of the recovery of oil and gas reserves;

the production and operating costs incurred; and

the amount and timing of future development expenditures.

If any of the above items turn out to be materially different than estimated, actual production, revenues and expenditures with respect to reserves will vary from estimates and the variances may be material.

The discounted future net revenues included in this document should not be considered as the market value of the reserves attributable to our properties. As required by the SEC, the estimated discounted future net revenues from proved reserves are generally based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net revenues will also be affected by factors such as:

the amount and timing of actual production;

supply and demand for oil and gas; and

changes in governmental regulations or taxation.

If we miscalculated our future cash requirements due to any of the risk factors detailed here or for any other reason, we would then need to service our existing bank debt and/or fund our growth strategy though additional financings and failure to obtain such financings would not only hamper our ability to expand our oil and gas operations but could result in a contraction of our business and activities.

Failure to raise such additional funds could materially adversely affect:

- our ability to participate in wells proposed to be drilled and the potential economic benefit that such wells might generate,
- our plans for aggressive expansion of our exploration activities,
- our ability to take advantage of opportunities to acquire interests in future projects on favorable terms, and
- our financial condition.

Without the availability of additional funds, we may be required to:

- reduce our operations and business activities,
- forfeit our interest in wells that are proposed to be drilled,
- farm-out our interest in proposed wells,
- sell a portion of our interest in proposed wells and use the proceeds to fund our participation for a lesser interest, or
- reduce our general and administrative expenses.

If additional financing is obtained by us, such financing:

- may not be available on terms that are advantageous to us,
- would dilute the percentage stock ownership of existing stockholders if additional equity securities are issued to raise the additional financing, and

could result in the issuance of additional equity securities which may have better rights, preferences or privileges than are available with respect to shares of our common stock held by our existing stockholders.

BUSINESS STRATEGY

In the fourth quarter of 2002, our Board of Directors made the decision to shift our Company s emphasis from higher risk exploration activities to lower risk exploitation and development opportunities. To facilitate this change, the decision was made to bring in new management in order to build the technical capabilities of our company and develop a more conservative portfolio of projects.

David A. Wilkins was hired as our new President and CEO on October 21, 2002, and after his arrival conducted a review of the existing assets of the company. Under his leadership our new mission statement is to exercise investment discipline in oil and gas projects while methodically building value for our shareholders.

There have been changes made in both our personnel and investment strategy. In November 2002, our Houston office was closed and all geological and geophysical (G&G) activity was relocated to the Tulsa office. This allowed us to centralize and better coordinate the operating, engineering and G&G functions. As part of the new technical focus for the Company, in 2003 we hired a total of four engineering and G&G personnel for the Tulsa office.

In August of 2003, our management presented a five-year strategic plan to our board. This plan established an objective of a compound annual growth rate over the five-year period for both reserves and production of 15% to 20%, to be achieved through organic growth of the existing asset base and acquisitions of new oil and gas reserves with development drilling opportunities. Utilizing management s price forecast, the estimated capital expenditures over the five-year period was $64 million, to be funded primarily through internally generated cash flow. Under the plan, we would attempt to:

Lower our debt to equity ratio to less than 40%;

Keep our finding and development costs within an acceptable range of $.80 to $1.75 per Mcfe (as adjusted from time to time to reflect the current product pricing and reserve category mix);

Maintain a well balanced portfolio of projects (from a risk standpoint);

Maintain a reserve ratio of at least 60% natural gas to 40% crude oil; and

Achieve acceptable annual growth rates through selected acquisition and development opportunities.

This plan was presented prior to the commencement of negotiations with Petrohawk. It is contemplated that material aspects of this plan will be implemented only if the Petrohawk transaction is not consummated. If the Petrohawk transaction is consummated, we will have an entirely new management team and a substantial amount of immediately available capital for our operations and acquisitions.

Our main goal is to maximize our value through profitable growth in our oil and gas reserves and productive capacity. We believe that our assets in the Mid-Continent region have not been fully developed. We have acreage in the Mid-Continent region which has not been drilled, and our focus in 2003 was to shift our efforts from the high-risk exploration projects in South Texas to these lower-risk Mid-Continent development projects. We expect to continue this focus. Our largest asset is the West Edmond Hunton Lime Unit (WEHLU) located primarily in Oklahoma County, Oklahoma, in which we have approximately a 98% ownership interest in 30,000 acres (Avalon Exploration, Inc. holds rights to participate in a continuous drilling program - please see WEHLU discussion below). We believe that this asset has infill development potential that we began pursuing in 2003. Accordingly, the largest portion of our 2004 capital budget will be expended on WEHLU. We will further pursue additional development drilling opportunities in other areas, such as our Hitchita Field in McIntosh County, OK. In 2003, we participated in the successful drilling of South Louisiana prospects in the Broussard and Lapeyrouse fields, with additional drilling expected in 2004. Due to the high drilling costs and operational risks associated with the South Louisiana wells, our ownership position in these wells was much lower than in our Mid-Continent wells. In 2003, we were not able to further evaluate our alternatives with our South Texas holdings, but believe that our geotechnical data covering this area has value. In addition, we will continue to assess potential changes in our asset mix through acquisition of new properties and/or divestiture of non-strategic properties deemed to have limited upside potential.

CRUDE OIL AND NATURAL GAS OPERATIONS

Our principal properties consist of developed and undeveloped oil and gas leases and the reserves associated with these leases. Generally, developed oil and gas leases remain in force so long as production is maintained. Undeveloped oil and gas leaseholds are generally for a primary term of three to five years. In most cases, the term of our undeveloped leases can be extended by paying delay rentals or by producing reserves that are discovered under those leases. Our revolving credit facility is collateralized by our proved developed reserves associated with our oil and gas properties and gas gathering system.

The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,					
	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (1)	2	.39	5	0.62	19	4.40
Dry	1	.35	5	0.83	12	2.71
Total Exploratory	3	.74	10	1.45	31	7.11
Development Wells:						
Productive (1)	18	4.34	8	1.84	14	3.23
Dry	7	1.94	3	0.58	4	0.63
Total Development	25	6.28	11	2.42	18	3.86
Total Wells:						
Productive (1)	20	4.73	13	2.46	33	7.63
Dry	8	2.29	8	1.41	16	3.34
Total	28	7.02	21	3.87	49	10.97

(1) Although a well may be classified as productive upon completion, future production may deem the well to be uneconomical, particularly for exploration wells where there is little or no production history.

At December 31, 2003, four gross (.46 net) wells were either drilling or in the completion process. Subsequent to December 31, 2003, drilling commenced on two gross (.66 net) wells which are currently in the completion and testing phase.

The following table sets forth a summary of the producing oil and gas wells and the developed and undeveloped acreage in which we owned an interest at December 31, 2003. We have not included in the table acreage in which our interest is limited to options to acquire leasehold interests, royalty or similar interests. Shut-in wells currently not capable of production are excluded from the producing well information.

	Producing Wells				Acreage			
	Oil		Gas		Developed		Undeveloped	
	Gross	Net (1)	Gross	Net (1)	Gross	Net (2)	Gross	Net
Texas	26	4.69	41	5.64	24,080.6	1,604.7	14,152.2	3,810.1
Oklahoma	30	15.30	89	56.16	54,986.3	42,341.9	1,548.9	563.5
Louisiana	1	0.12	11	0.90	8,329.8	942.5	3,073.2	879.3
Kansas	17	15.05	3	2.35	4,987.5	4,006.0	7,243.5	2,951.2
	74	35.16	144	65.05	92,384.2	48,895.1	26,017.8	8,204.1

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(1) Net wells are computed by multiplying the number of gross wells by our working interest in the gross wells.

(2) Net acres are computed by multiplying the number of gross acres by our working interest in the gross acres.

Approximately 9,320 gross acres and 3,198 net acres of unevaluated leasehold are scheduled to expire in 2004. The Company may not extend or renew some or all of this leasehold due to condemnation by previous exploration activity or change in our strategic emphasis.

At December 31, 2003, we had proved reserves of 1,307.5 MBbls of oil and 22.4 Bcf of gas as estimated by Netherland Sewell & Associates, Inc., an independent engineering firm. These reserves are located entirely within the United States. The following table sets forth, at December 31, 2003, these reserves and the present value, discounted at an annual rate of 10%, of our future net revenues (revenues less production and development cost) attributable to these reserves.

	Proved Developed	Proved Undeveloped	Total Proved
Oil (Bbls)	984,465	323,084	1,307,549
Gas (Mcf)	19,623,963	2,776,154	22,400,117
Future Net Revenues (before income taxes)	$ 85,213,500	$ 15,813,600	$ 101,027,100
Present value of Future Net Revenue (before income taxes)	$ 47,547,300	$ 10,940,700	$ 58,488,000
Present value of Future Net Revenue (after income taxes)	$ 40,153,118	$ 9,206,262	$ 49,359,380

The above figures do not reflect the estimated December 31, 2003 future net revenues and the present value of future net revenues, discounted at an annual rate of 10%, for our McIntosh, Oklahoma gathering system, which were $2,170,600 and $1,626,600, respectively, nor do they reflect the cash flows associated with asset retirement obligations.

For purposes of determining the above cash flows, estimates were made of quantities of proved reserves and the periods during which they are expected to produce. Future cash flows were computed by applying year-end prices to estimated annual future production from our proved oil and gas reserves. The year-end prices for crude oil and natural gas used in the estimation were $29.25 per Bbl, based on a December 31, 2003, West Texas Intermediate posted price, and $5.97 per MMbtu, based on a December 31, 2003, Henry Hub spot market price, respectively. These prices were adjusted by lease for quality or energy content, transportation fees and regional price differentials. Future development and production costs were computed by applying year-end costs expected to be incurred in producing and further developing the proved reserves. The estimated future net revenue was computed by application of a 10% per annum discount factor. The calculations assume the continuation of existing economic, operating and contractual conditions. Other assumptions of equal validity could give rise to substantially different results.

For additional information on our oil and gas reserves, please refer to **Item 8. Financial Statements and Supplementary Data, Note 14**. **UNAUDITED SUPPLEMENTARY OIL AND NATURAL GAS INFORMATION**.

Our oil and gas reserves are not subject to any long-term supply arrangement with foreign governments or authorities. Our estimated reserves have not been filed with or included in reports to any federal agency other than the SEC and U.S. Department of Energy, FORM EIA-23, Annual Survey of Domestic Oil and Gas Reserves for 2003.

We account for our oil and gas producing activities using the full cost method of accounting as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general corporate costs are expensed as incurred. In general, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded. Amortization of evaluated oil and gas properties is computed on the units of production method based on all proved reserves on a country-by-country basis. Unevaluated oil and gas properties are assessed at least annually for impairment either individually or on an aggregate basis. The net capitalized costs of evaluated oil and gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, and the lower of cost or estimated fair value of unproved properties, net of tax considerations. For further discussion please refer to **Item 8. Financial Statements and Supplementary Data, Note 2. ACQUISITIONS, SALES AND OIL AND GAS OPERATIONS**.

Capitalized costs of our evaluated and unevaluated properties at December 31, 2003, 2002 and 2001 are summarized as follows:

	December 31, 2003		**December 31, 2002**		**December 31, 2001**	
	United States	**Foreign**	**United States**	**Foreign**	**United States**	**Foreign**
Capitalized costs-Evaluated properties	$ 76,906,831	$ 1,810,549	$ 69,226,520	$ 1,680,921	$ 57,027,523	$ 1,680,921
Unevaluated properties	1,294,212		4,453,326	129,279	12,872,623	128,820
	78,201,013	1,810,549	73,679,846	1,810,200	69,900,146	1,809,741
Less-Accumulated depreciation, depletion, amortization & impairment	(37,929,567)	(1,810,549)	(33,452,175)	(1,681,270)	(23,377,455)	(1,681,270)
	$ 40,271,476	$	$ 40,227,671	$ 128,930	$ 46,522,691	$ 128,471

We commenced sales of oil and gas in 1999. Our average sales price, oil and natural gas production volumes and average production cost for each Mcfe of natural gas production for the periods indicated were as follows:

	Year Ended December 31,		
	2003	**2002**	**2001**
Oil production (Bbl)	128,831	124,720	114,271
Gas production (Mcf)	1,859,081	2,249,371	2,512,484
Average sales price:			
Oil (per Bbl)	$ 27.36	$ 21.68	$ 24.72

Gas (per Mcf)	$	4.69	$	2.91	$	3.97
Average production cost per Mcfe	$	1.19	$	1.10	$	1.08

The average oil and gas sales prices above reflect the impact of any hedges. Our 2003 average natural gas price was reduced by $.59 per Mcf and average crude oil price was reduced by $1.80 per Bbl due to our hedges. In 2002, the impact of hedges reduced our average natural gas price by $0.25 per Mcf and our average crude oil price by $1.76 per Bbl.

Location of Operations

Our current areas of operations and holdings include Oklahoma, Louisiana, Kansas and Texas. The following discussion summarizes our present operations and properties, acreage position, results from 2003 and future plans.

Oklahoma

WEHLU

The West Edmond Hunton Lime Unit (WEHLU) is our largest asset, covering 30,000 acres (about 47 square miles) primarily in Oklahoma County, Oklahoma. The WEHLU Field, originally discovered in 1942, is the largest Hunton Lime

Field in the state of Oklahoma. The field has 55 oil and natural gas wells (22 currently producing) with stable production holding the entire unit. We hold a 98% working interest at WEHLU and we are the operator. At December 31, 2003, WEHLU had proven reserves of approximately 20.3 Bcfe or approximately 67% of our total proven reserves. WEHLU currently produces approximately 3.4 MMcfe per day or 45% of our current net production.

We have an agreement with Avalon Exploration, Inc. of Tulsa, Oklahoma (Avalon) to jointly test and develop additional production in WEHLU. The area of mutual interest (AMI) to be evaluated by our agreement with Avalon covers 5,680 acres located in the Central-Northwest area of the field.

As of December 31, 2003, Avalon had drilled five wells in WEHLU under our agreement. The first four wells, drilled under a pilot program with Avalon, resulted in one dry hole and three completions. The first two pilot wells were drilled to test the productivity of the lower Hunton (Chimney Hill) formation in the western portion of the unit. Of these two wells, one well was non-productive in the lower Hunton but was successfully re-completed in the Upper Hunton (Bois d Arc) formation. The other well was plugged and abandoned. The last two pilot wells were drilled and successfully completed in the Upper Hunton formation. Avalon paid 100% of the drilling and completion costs for the pilot wells. In the three successful pilot wells, we have a 30% working interest after the pilot program reaches payout. We anticipate the pilot program to payout during 2004. Under the "pilot" program we have a "look-back" right to participate with a 10% working interest after the wells were drilled and completed, if successful. To exercise the "look-back" right, we would reimburse Avalon 10% of its historical costs in the pilot wells at the exercise date of the right. We elected not to exercise our look-back right to participate in the four pilot wells due to the excessive historical cost associated with the one dry hole.

Avalon also drilled their first development well in WEHLU during 2003. This well was successfully completed in the Upper Hunton formation and we participated with a 40% working interest.

A summary of the current gross production resulting from the Avalon drilling at WEHLU is listed below:

Well	**Program**	**Oil - Bbl per day**	**Gas Mcf per day**	**Water Bbl per day**
Recount	Pilot	Dry Hole		
Mable T	Pilot	10	216	280
Damogram	Pilot	46	283	220
Willey	Pilot	230	536	300
Court Reception	Development	37	204	327

Currently, we are negotiating with Avalon regarding the drilling of a water disposal well to reduce water disposal costs. Avalon plans on drilling four wells in 2004. We anticipate participating in the drilling of these wells.

We have committed approximately $2.9 million, or 58%, of our 2004 capital budget for drilling and re-working wells in the WEHLU area. The focus will be as follows:

Continue our reactivation program of selected shut-in wells;

Application of new stimulation techniques to certain existing wells for production optimization;

Participation in the Avalon drilling program; and

Drilling of two wells outside of the Avalon AMI.

McINTOSH COUNTY

We hold approximately 13,572 gross (9,571 net) acres of oil and gas leases and have interests in 60 gross (36 net) wells. We operate 43 of these wells in the N.E. Hitchita Field. In 2003, we participated in the drilling of 4 gross (1.66 net) wells, of which two gross (.94 net) wells were successful completions, one gross (.68 net) well was a dry hole and one gross (.05 net) well is in the completion stage. The current net daily production from the McIntosh area is approximately 1,745 gross (472 net) Mcf of natural gas.

The gas produced is dry and is sold into a low-pressure gathering system of our subsidiary, Red River Field Services, L.L.C. The gathering system presently includes approximately 40 miles of pipeline and is connected to 49 wells, including the wells in which we have an interest. During 2003, our gas gathering system in this area had gathering revenues of approximately $648,200.

Louisiana

Since 1999, we have invested approximately $14.7 million in leases, seismic data collection and drilling in South Louisiana, both onshore and offshore. Currently, we have production in the Lapeyrouse Field located in Terrebonne Parish, the Broussard Field located in Lafayette Parish as well as production in shallow waters of West Cameron Blocks 39 and 49 located offshore Cameron Parish. We have working interests in 10 gross (.9 net) producing wells that have a current net daily production of 1.8 MMcfe of natural gas. Our working interest in the producing wells range from 2.0% to 16.7%. We have leasehold positions in the West Broussard Field in Lafayette Parish and the Lapeyrouse Field in Terrebonne Parish.

LAPEYROUSE PROJECT

The Lapeyrouse Prospects are located in Terrebonne Parish, Louisiana where we have a leasehold position covering 2,632 gross (201 net) acres. Within this acreage position, we have two proven undeveloped locations and two probable locations identified for future drilling. During 2003, we participated in the drilling and completion of one gross (.03 net) well and one gross (.05 net) well in which drilling commenced in 2003 but was completed subsequent to December 31, 2003. For 2004, we anticipate participating in the drilling of three wells in this area.

WEST BROUSSARD PROSPECT

The West Broussard Prospect is located in Lafayette Parish, Louisiana and covers approximately 1,126 gross (791 net) acres. We began acquiring acreage offsetting two high-rate natural gas wells in 2001. In 2002, two drilling units were created known as the East and West units. Additionally in 2002, we sold down our leasehold position to industry partners in the East unit for $1,300,000 and certain promoted working and reversionary interests in future wells to be drilled in this unit and giving the industry partner an option to purchase an interest in the West unit. In 2003, the M. A. Failla #1 well was drilled and completed on the East unit. Currently, the well is producing approximately 17,900 gross (619 net) Mcf of natural gas and 440 gross (15 net) barrels of condensate per day. We have a 4.8% working interest in this well, increasing to 10.1% working interest after well payout which is estimated to occur in the first quarter of 2004.

With the success of the M.A. Failla #1, additional development of the West unit will occur in 2004. Currently, the Montesano #1 (formerly known as the Landry #1) located in the West unit is permitted and scheduled to commence drilling late in the first quarter of 2004. In October 2003, our partner notified us it elected not to exercise its option to drill a well in the West unit. At that time, we had a working interest ownership in the West unit of approximately 83.6%. Subsequent to December 31, 2003, we entered into an arrangement with three parties, whereby upon closing of the arrangement we will receive approximately $731,500 for approximately 74% of our working interest in the prospect. Additionally, we will receive approximately $1.1 million in production payments from future net cash flow from the well, if successful, and will receive an additional 4.2% working interest after well payout. Upon closing of the arrangement, we will have a 9.6% working interest in the well increasing to a 13.8 % working interest after well payout.

At December 31, 2001, the proven undeveloped reserves for the West Broussard prospect were 7.3 Bcf of natural gas and 122 MBbl of condensate, representing approximately 27% of our total proved reserves. At December 31, 2002, the reserves were reclassified from the proved category to a less certain category due to unexpected water and sand production in the adjacent well. Positive results from the M.A. Failla #1 supported revision of the classification of reserves back to the proved category at December 31, 2003. At December 31, 2003, our total net proved reserves for the Broussard field were 2.1 Bcf of natural gas and 45.1 MBbl of condensate, representing approximately 8% of our total net proved reserves. For further discussion on reserves see **Item 8. Financial Statements And Supplementary Data, Note 2. ACQUISITIONS,**

SALES AND OIL AND GAS OPERATIONS and Note 14. UNAUDITED SUPPLEMENTARY OIL AND NATURAL GAS INFORMATION.

Texas

JACKSON COUNTY

Jackson County Texas was the focal point of our exploration activities from 1997 until 2002. We participated in four project areas, known as Texana, Formosa Grande, Ganado and BWC, to acquire proprietary 3-D seismic information on approximately 185,000 acres. Drilling commenced on these properties in 1999 and resulted in a total of 28 (3.9 net) discoveries out of 45 (7.1 net) wells drilled to date. The successful wells were shallow-to-deep Frio and Yegua tests. We did not have a successful Deep Wilcox test. Parallel Petroleum Corporation, Allegro Investments, Inc. and Sue Ann Production, Inc. operate the majority of our Jackson County properties and our participation levels have ranged from 12.5% to 25%. We have spent approximately $19.7 million since inception on lease acquisition, seismic and drilling activity. Currently, our average net daily production for Jackson County is approximately 715 Mcfe of natural gas, or 10% of our total net daily production.

In the fourth quarter of 2002, we decided to shift our emphasis from higher risk exploration activities to lower risk exploitation opportunities, focusing on areas where we are active as the operator. We will continue our efforts to identify exploration prospects in Jackson County, however, due to the high risk profile of these prospects and the associated high drilling costs, we plan to sell down or farmout our interests in all future prospects. We are evaluating ways to create additional value by exchanging our existing Jackson County 3-D seismic data for similar data in other areas, at no additional cost to our company. Due to the results to date and our change in business strategy, we have impaired the unevaluated costs, associated with seismic for Jackson County in 2003 and 2002, for $1.6 million and $4.9 million, respectively, for a total of $6.5 million. These costs were transferred to our U.S. evaluated properties and included in our full cost pool.

Mexican Sweetheart Project

The prospect is located to the southeast of the Texana project and is a deep Yegua test, which was based on 3-D seismic data. We have 360 gross (132 net) acres under lease and have a 36% working interest in the prospect. We plan to sell down out interest in this prospect to industry partners and retain a carried interest and/or a reversionary interest. The leases expire in the third quarter of 2004.

North Mexican Sweetheart

In 2001, we acquired a 100% interest in 2,120 acres to the north of our Mexican Sweetheart Project. In 2002, we sold our acreage position for cash and a reversionary interest of 12.5% after pay out in the exploratory well. In 2003, a dry hole was drilled in offsetting acreage. As such, plans to drill the prospect were cancelled and the remainder of the prospect costs were impaired and transferred to the U.S. domestic cost pool.

WHARTON COUNTY

King Louie

In 2001, we acquired a 100% interest in 1,229 acres in Wharton County, Texas. Subsequent drilling on nearby acreage resulted in an apparent Wilcox discovery. In 2003, we exchanged 50% of our interest in the prospect to a third party operator who paid 100% of the 2003 delay rentals, which were approximately $46,000. The operator is currently seeking additional partners to drill the prospect. Subsurface geology and seismic work is underway to better delineate the prospect. The acreage position expires in the third quarter of 2004.

WALLER COUNTY

Brookshire Dome

The Brookshire Dome field is a salt dome field located approximately 30 miles west of Houston in Waller County, Texas. Beta acquired interests in existing production in the Brookshire Dome area in mid-2001. Based on the success of a shallow Miocene play south of our acreage block, an intensive drilling program was initiated in the second half of 2001 which targeted similar shallow Miocene oil and gas sands above the salt dome. The potential also exists for deeper sub-salt Yegua and Wilcox objectives. To date we have leased approximately 4,613 gross (440 net) acres for both exploration and exploitation opportunities.

Revere Corporation and Johnson Sanford are the operators of the wells in which we have an interest. Revere is currently very active in drilling the shallow Miocene targets and under the agreement in place, we have the option to either participate or farm out on a well-by-well basis. In 2003, we sold down certain of our working interests to Revere. Under the terms of the sale, Revere is responsible for funding the drilling of four shallow exploration wells and two deep exploration wells. We received a 6.25% carried working interest in the shallow wells and 12.5% carried interest in the deep wells on the drilling costs associated with these wells. As of December 31, 2003, Revere had drilled all four shallow exploratory wells and one of the deep exploratory wells. The shallow wells were successful and completed as producing wells, while the deep well was a dry hole. Revere plans to drill the second deep exploratory well in 2004. We participated in the drilling of 10 gross (1.1 net) wells of which eight gross (.91 net) wells were successful. Currently, we have interests in 27 gross (5.2 net) wells at Brookshire Dome. Our total current daily average production is 912 gross (100 net) Mcf of natural gas and 1,106 gross (162 net) Bbl of oil. The net amount expended to date in the Brookshire Dome area is $3.7 million.

GALVESTON COUNTY

Greens Lake Project

The Rubel #1 (known as the Sara White Prospect), operated by Ocean Energy, was spuded in the fourth quarter of 2001 and completed during the second quarter of 2002. A production test was performed and the well tested at a flow of 2.1 MMcf per day of natural gas and 30 Bbls of condensate per day. The well commenced sales in August 2002, after a considerable delay due to right-of-way issues regarding the sales line. Due to water encroachment, the production quickly declined to uneconomic levels. The operator attempted to eliminate the water in the initial zone (S sand) but was unsuccessful. Subsequent recompletions up hole were also unsuccessful. In mid-2003, the operator farmed out the well to another third party operator, who desired to re-enter the well and attempt recompleting certain zones that could potentially be prospective. To date there have been no positive results. If successful, we would have a 28.7% interest in the well but no further capital risked for the attempted re-entry. If the current project to restore production is unsuccessful, the leases for this prospect will expire. We originally had a 31% working interest in this well and our net expenditure was approximately $2.8 million.

RED RIVER AND LAMAR COUNTIES

The Detroit Project

In 2003, considerable effort was expended, along with an industry partner who had a similar acreage position in this area, in marketing this prospect for drilling. However the effort was not successful. The Detroit prospect, a large NE-SW trending seismically controlled feature in the Northwestern portion of Red River County and Eastern Lamar County in Northeast Texas, covered 9,401 gross (7,050 net) acres. The high-risk exploration prospect was developed as a rework of existing seismic data and an extensive radiometric survey of the entire area for surface detection of hydrocarbons. The majority of the original leases was consummated in 2000 and had primary lease terms ranging from two to three years. The remainder of the existing leases expired in 2003. Our total cost for acreage, seismic and other geological and geophysical activity was approximately $880,000.

SEASONALITY OF BUSINESS

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of results, which may be realized on an annual basis.

MARKETS AND CUSTOMERS

Our oil and gas production is sold at the well site on an as-produced basis at market-related prices in the areas where the producing properties are located. We do not refine or process any of the oil or natural gas we produce. Approximately 97% of our production is sold to unaffiliated purchasers on a month-to-month basis.

In the table below, we show the purchasers that each accounted for 10% or more of our revenue during the specified years.

	2003	**2002**	**2001**
Duke Energy Field Services, LLC	33%	31%	29%

Allegro Investments	10%	14%	16%
Sunoco, Inc.	10%	9%	7%

We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and gas we produce. Other purchasers are available in our areas of operations.

The marketability of our oil and gas reserves, or of reserves which we may acquire or discover, may be affected by numerous factors beyond our control. These factors include fluctuations in product markets and prices, the proximity and capacity of pipelines to our oil and gas reserves, our ability to finance exploration and development costs and the availability of processing equipment. Additional factors are engineering and construction delays, difficulties and hazards resulting from unusual or unexpected geological or environmental conditions, or to the conditions involved in drilling and operating wells.

We are not obligated to provide a fixed and determinable quantity of oil or natural gas under any existing arrangements or contracts. We expect to use hedge arrangements on a limited basis as necessary to partially protect against commodity price volatility.

Our business does not require us to maintain a backlog of products, customer orders or inventory.

COMPETITIVE CONDITIONS IN THE BUSINESS

The petroleum and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market petroleum and natural gas, as well as, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, and obtaining purchasers and transporters of the oil and gas we produce. There is also competition between petroleum and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments (and/or agencies thereof) of the United States and Canada; however, it is not possible to predict the nature of any such legislation and/or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil and gas and may prevent or delay the commencement or continuation of a given operation. The exact effect of these risk factors cannot be accurately predicted.

OPERATIONAL RISKS

Oil and gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and gas in commercial quantities. Oil and gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other circumstances that may cause accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property may occur. In such event, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could substantially reduce available cash and possibly result in loss of oil and gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations.

REGULATIONS

Domestic exploration for, and production and sale of, oil and gas are extensively regulated at both the federal and state levels. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and gas industry that often are costly to comply with and that carry substantial penalties for failure to comply. In addition, production operations are affected by changing tax and other laws relating to the petroleum industry, constantly changing administrative regulations and possible interruptions or termination by government authorities.

State regulatory authorities have established rules and regulations requiring permits for drilling operations, drilling bonds and reports concerning operations. Most states in which we operate also have statutes and regulations governing a number of environmental and conservation matters, including the unitization or pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Many states also restrict production to the market demand for oil and gas. Such statutes and regulations may limit the rate at which oil and gas could otherwise be produced from our properties.

We are subject to extensive and evolving environmental laws and regulations. These regulations are administered by the United States Environmental Protection Agency (EPA) and various other federal, state, and local environmental, zoning, health and safety agencies, many of which periodically examine our operations to monitor compliance with such laws and regulations. These regulations govern the release of waste materials into the environment, or otherwise relating to the protection of the environment, human, animal and plant health, and affect our operations and costs. In recent years, environmental regulations have taken a cradle to grave approach to waste management, regulating and creating liabilities for the waste at its inception to final disposition. Our oil and gas exploration, development and production operations are subject to numerous environmental programs, some of which include solid and hazardous waste management, water protection, air emission controls, and situs controls affecting wetlands, coastal operations, and antiquities.

Environmental programs typically regulate the permitting, construction and operations of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Once operational, enforcement measures can include significant civil penalties for regulatory violations regardless of intent. Under appropriate circumstances, an administrative agency can request a cease and desist order to terminate operations.

New programs and changes in existing programs are anticipated, some of which include Natural Occurring Radioactive Materials (NORM), oil and gas exploration and production waste management, and underground injection of waste materials.

Each state in which we operate has laws and regulations governing solid waste disposal, water and air pollution. Many states also have regulations governing oil and gas exploration, development and production operations.

We are also subject to Federal and State Hazard Communications (OSHA) and Community Right to Know (SARA Title III) statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances. We believe we are in compliance with these requirements in all material respects.

We may be required in the future to make substantial outlays to comply with environmental laws and regulations. The additional changes in operating procedures and expenditures required to comply with future laws dealing with the protection of the environment cannot be predicted.

EMPLOYEES

As of the date of this annual report, we employ 12 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

PREMISES

In January 2004 our office lease expired. Under that arrangement, we leased approximately 6,400 square feet in Tulsa, Oklahoma, which included office and storage space and required a monthly payment of approximately $9,300. We currently have entered into a short-term lease arrangement for approximately 7,200 rentable square feet that requires a monthly payment of approximately $10,770. The lease term covers the period March 1, 2004 to April 30, 2004 and may be continued on a month-to-month basis. All of our corporate functions and some operational functions are conducted from this site. This arrangement will terminate should the Petrohawk transaction be consummated. For further discussion of the Petrohawk transaction, see **Item 1. Business and Item 2. Properties GENERAL Petrohawk transaction** above.

We also maintain two field offices, of which one is located in south Tulsa County, Oklahoma and the other is located in Edmond, Oklahoma.

Item 3. Legal Proceedings

None

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of our shareholders during the fourth quarter of the fiscal year ended December 31, 2003.

No matters were submitted to a vote of our shareholders during the fourth quarter of the fiscal year ended December

PART II

Item 5. Market Price for Registrant s Common Equity and Related Stockholder Matters

Our common stock began trading July 9, 1999 on the Nasdaq Small Cap Market under the symbol BETA . On May 4, 2000 we were accepted on the Nasdaq National Market. The following table sets forth for the fiscal periods indicated the range of the high and low bid prices of our common stock as reported on the Nasdaq National Market for each quarter in those periods. We have not paid any cash or other dividends, other than those dividends associated with our preferred stock, since inception**.** For the foreseeable future, we intend to retain any funds otherwise available for dividends.

	High	Low
2003		
1st Quarter	$ 1.07	$ .69
2nd Quarter	1.65	.62
3rd Quarter	1.52	1.15
4th Quarter	2.36	1.30
2002		
1st Quarter	$ 5.30	$ 3.26
2nd Quarter	4.20	2.01
3rd Quarter	2.20	1.11
4th Quarter	1.31	0.80

Approximately 193 shareholders of record and approximately 3,110 beneficial owners as of March 16, 2004 held the common stock. In many instances, a registered shareholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

Item 6. Selected Financial Data

Summary Financial Information for Beta

The following tables presents selected historical financial data derived from our Financial Statements as well as selected historical quarterly financial data. The following data is only a summary and should be read with our historical financial statements and related notes contained in this document. The acquisition of Red River Energy, Inc. in 2000 affects the comparability between the Financial Data for the periods presented.

	For the years ended December 31,				
	2003	**2002**	**2001**	**2000**	**1999**
Income Statement Data:					
Operating revenues	$ 12,924,689	$ 9,647,841	$ 13,656,521	$ 8,357,867	$ 1,199,480
Operating expense (1)	3,359,239	3,500,351	3,808,523	1,516,113	81,538
General and administrative	3,082,605	2,209,887	2,679,121	2,141,005	1,418,240
Impairment expense	129,279	5,163,689	13,805,035		1,224,962
Depreciation and depletion expense	4,857,597	5,120,572	5,176,897	2,693,439	914,233
Interest expense	476,078	558,297	867,835	393,008	2,966,651
Net income (loss)	967,497	(6,881,612)	(9,046,084)	1,425,565	(5,384,403)
Earnings (loss) per share:					
Basic	$ .04	$ (.59)	$ (.75)	$ .13	$ (.66)
Diluted	.04	(.59)	(.75)	.13	(.66)
Weighted average common shares and equivalent outstanding:					
Basic	12,431,530	12,417,957	12,368,373	10,616,692	8,160,000
Diluted	12,506,835	12,417,957	12,368,373	11,281,413	8,160,000
Balance sheet data:					
Working capital	$ 1,896,502	$ (77,047)	$ (103,550)	$ 3,533,237	$ 2,034,268
Total assets	46,115,243	44,753,260	52,629,378	58,466,152	20,881,475
Total long term debt	13,284,652	13,634,652	13,648,727	13,814,034	27,939
Stockholder s equity	29,269,615	28,048,137	35,874,474	40,060,406	20,588,237
Proved Reserves					
Oil (Mbbls)	1,307.5	608.6	836.8	814.0	13.2
Gas (MMcf)	22,400.5	14,688.2	24,710.0	19,418.0	4,170.0
Total (MMcfe)	30,245.4	18,320.0	29,730.8	24,302.8	4,249.2

Approximately 193 shareholders of record and approximately 3,110 beneficial owners as of March 16, 2004 held th

Present value of estimate future net revenues before income tax discounted at 10%	$ 58,488,000	$ 35,929,439	$ 31,295,012	$ 100,199,288	$ 6,012,972
Standardized measure (2)	$ 48,333,104	$ 35,929,439	$ 31,295,012	$ 71,458,654	$ 6,012,972

(1) Operating expense includes production taxes and field service expense associated with our McIntosh gathering system.

(2) Includes reduction of $1,026,276 for asset retirement obligation.

Approximately 193 shareholders of record and approximately 3,110 beneficial owners as of March 16, 2004 held th

SELECTED QUARTERLY FINANCIAL DATA

	For the quarter ended			
(In Thousands of Dollars except for per share amounts)	March 31	June 30	September 30	December 31
2003				
Revenues	$ 3,101.2	$ 3,042.7	$ 3,276.5	$ 3,504.3
Revenues less operating expense	2,265.6	2,278.8	2,489.0	2,532.0
General and administrative expense	813.8	677.6	742.2	849.0
Net income (loss)	(16.8)	187.0	413.8	383.5
Earnings (loss) per share:				
Basic	(.01)	.01	.02	.02
Diluted	(.01)	.01	.02	.02
2002				
Revenues	$ 2,343.2	$ 2,547.6	$ 2,323.2	$ 2,433.8
Revenues less operating expense	1,563.1	1,570.8	1,408.4	1,605.2
General and administrative expense	475.4	457.6	453.6	823.3
Net income (loss)	(206.2)	(160.4)	(377.6)	(6,137.4)
Earnings (loss) per share:				
Basic	(.03)	(.02)	(.04)	(.50)
Diluted	(.03)	(.02)	(.04)	(.50)
2001				
Revenues	$ 4,696.1	$ 3,809.6	$ 2,531.3	$ 2,619.5
Revenues less operating expense	3,748.5	2,926.5	1,623.7	1,549.3
General and administrative expense	570.2	682.8	611.2	814.9
Net income (loss)	905.7	388.0	(4,657.0)	(5,682.9)
Earnings (loss) per share:				
Basic	.07	.03	(.39)	(0.46)
Diluted	.07	.03	(.39)	(0.46)

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is to inform you about our financial position, liquidity and capital resources as of December 31, 2003 and 2002, and the results of operations for the years ended December 31, 2003, 2002 and 2001.

Overview

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided from operations which was a result of a favorable commodity price environment during 2003, 2.) a successful exploration, exploitation and development capital program resulting in a 65% net increase in our proved reserves, and 3.) an increase in our exit daily production rate from 7.5 Mcfe at December 31, 2002, to 7.8 Mcfe at December 31, 2003. Conversely, our total 2003 production volume decreased approximately 12% from 2002 and our general administrative expenses increased from 2002 by approximately 39%. We continue to be optimistic about the long-term outlook for natural gas and crude oil but realize that the overall environment for commodity pricing is very volatile and can be materially affected, favorably or unfavorably, by such factors as imports/exports, weather trends, power generation and industrial demands.

The discussion in this section regarding 2004 and subsequent periods are all subject to the effects of consummating the proposed transaction which is discussed in **Item 1. Business and Item 2. Properties GENERAL Petrohawk Transaction**.

Liquidity and Capital Resources

A company s liquidity is the amount of time expected to elapse until an asset can be converted to cash or conversely until a liability has to be paid. Liquidity is one indication of a company s ability to meet its obligations or commitments. Historically, our major sources of liquidity have come from internally generated cash flow from operations, funds generated from the exercise of warrants/options and proceeds from public and private stock offerings.

The following table represents the sources and uses of cash for the years indicated.

	For the years ended December 31,		
	2003	**2002**	**2001**
Beginning cash balance	$ 927,313	$ 556,199	$ 1,536,186
Sources of cash:			
Cash provided by operations	5,998,306	2,977,752	9,047,095
Cash provided by financing activities	284,852	328,637	6,822,927
Cash provided by sales of oil & gas properties and Equipment	549,287	3,231,944	1,082,524
Total sources of cash including cash on hand	7,759,758	7,094,532	18,488,732
Uses of cash:			
Oil and gas expenditures, net of prepaid drilling advances	(4,259,534)	(5,442,418)	(15,653,461)
Other equipment	(52,022)	(36,103)	(177,103)
Cash used by financing activities	(1,338,521)	(688,698)	(2,101,969)
Total uses of cash	(5,650,077)	(6,167,219)	(17,932,533)
Ending cash balance	$ 2,109,681	$ 927,313	$ 556,199

Working capital and liquidity:

Our working capital was a surplus of $1,896,502 at December 31, 2003, compared to a deficit of ($77,047) at December 31, 2002. The significant increase in our working capital and liquidity for the twelve months ended December 31, 2003, was due to an increase in cash flow from operations resulting from a higher natural gas and crude oil price environment, lower operating expense partially offset by an increase in general and administrative expense and lower oil and gas capital expenditures. Additionally, at December 31, 2003, we had no futures derivative liability associated with our future production volume compared to a futures derivative liability at December 31, 2002, of $702,417, which represented the potential unrealized reduction in our future oil and gas revenue based on the current outstanding derivative contracts at that time.

Our principal source of short-term liquidity is from internally-generated cash flow. Should natural gas and crude oil prices decrease materially, our current operating cash flow would decrease and our liquidity and working capital position would be negatively impacted and could adversely impact our growth capability.

Current borrowing base:

Our borrowing base capacity under the current credit facility is presently not a material source of capital. Historically, we have not used credit facilities for a source of funds in our drilling or leasing activity. Should proved developed reserves

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

not materially increase and/or if pricing materially declines, our borrowing base could be reduced below the amount currently borrowed and outstanding under the facility. If this event were to occur we would be obligated to pay down the outstanding amount to the re-determined borrowing capacity. We would rely on cash flow from operations and funds generated from the sale of unevaluated and/or proved undeveloped properties to make this pay down. It is possible that we would have to sell some non-core assets as well in order to meet this obligation. The current credit agreement, which was re-determined and extended during the quarter ended June 30, 2003, has a maturity date of April 1, 2005 and a current borrowing capacity of $13,972,000 subject to an automatic monthly reduction of $88,000, which commenced on July 31, 2003. At December 31, 2003, a balance of $13,284,652 was outstanding against the borrowing base and the effective interest rate, which is a LIBOR base rate plus 2.2%, was 3.37%. During 2003, we reduced our outstanding debt balance by $350,000 which was lower than projected. Due to unplanned expenditures associated with the pending Petrohawk transaction as discussed further below, additional voluntary paydowns to the outstanding debt were deferred.

2003 capital expenditures:

For the twelve months ended December 31, 2003, we expended approximately $4.2 million (including changes in prepaid drilling advances) primarily comprised of:

$1.2 million related to our South Central Kansas drilling program - Approximately $.4 million was expended on acreage and seismic and approximately $.8 million has been incurred for drilling activity through December 31, 2003. In July 2003, we committed to a 13-well drilling program located within a six-county area in the Mississippian subcrop belt of South Central Kansas, which covers approximately 13,500 gross acres. We have a 35% working interest in the program. All of the prospects are at depths of approximately 5,000 feet with 11 of the 13 prospects classified as infill-development wells and the remaining two prospects classified as new field exploratory wells. Drilling commenced during the 3rd quarter of 2003 and to date, 13 gross (4.55 net) wells have been drilled, with seven gross (2.45 net) wells deemed successful, four gross (1.4 net) wells were dry holes and two gross (.7 net) wells drilling or in the completion stage. Currently, five gross (1.75 net) wells are producing a total of approximately 940 gross (270 net) mcfe of natural gas per day. Four gross (1.4 net) wells are awaiting pipeline connection.

$.8 million expended on recompletion and drilling activity at WEHLU, Oklahoma County, OK. To date seven gross (6.9 net) wells have been recompleted or stimulated and we have participated in the drilling of one gross (.4 net) well that was completed subsequent to the fourth quarter of 2003. The new well is currently producing approximately 25 gross (8 net) barrels per day and 300 gross (96 net) Mcf per day. We estimate that our daily production has increased by approximately 28 gross (22 net) barrels and 185 gross (145 net) Mcf from our recompletion and remediation activity.

$.5 million expended for drilling, completion, workovers and conversion to salt water disposal in the Brookshire Dome area, Waller County, TX. In 2003, we participated in the drilling of 10 gross (1.1 net) wells, of which eight gross (.91 net) wells were successful, two gross (.2 net) well were dry holes. Our current daily production rate from this activity is approximately 879 gross (100 net) Mcf of natural gas and 258 gross (59 net) Bbl of oil.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

$.4 million expended on the drilling and completion of the M.A. Failla No. 1, Broussard Field, Lafayette Parish, LA, which was tested in the first quarter of 2003 and commenced sales on September 30, 2003. We have a 4.8% working interest in the well, increasing to approximately 10% working interest after well payout. The well is currently producing approximately 17,900 gross (619 net) Mcf of natural gas and 440 gross (15 net) Bbl of condensate per day.

$.3 million expended on drilling and recompletion activity in McIntosh County and Tulsa County, OK. During the twelve months ended December 31, 2003, we participated in the drilling of four gross (1.6 net) wells in McIntosh County, OK of which two gross (.9 net) wells were successful, one gross (.7 net) well was a dry hole and one gross (.05 net) well is awaiting completion. Currently, the two successful wells are producing 268 gross (88 net) Mcf of natural gas per day.

$.4 million expended on the drilling and completion of two prospects located in the Lapeyrouse field, Terrebonne Parish, Louisiana. We participated with a 3.1% working interest in the A.M. Dupont #2, which was a successful development well and is currently producing approximately 4,050 gross (90 net) Mcf of natural gas and 52 gross (1 net) Bbl of condensate per day. Subsequent to December 31, 2003, the J.C. Dupont was successfully completed in which we have a 4.1% working interest. The well is currently producing approximately 1,055 gross (31 net) Mcf of natural gas per day.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

$.2 million expended on other projects with minority interest in South Texas. Those projects included a participation with a 2.4% working interest in an exploratory well located in Wharton County, TX which was a dry hole and a recompletion attempt in the Rubel #1 located in Galveston County, TX which was also unsuccessful.

Petrohawk transaction:

On December 12, 2003, we entered into a securities purchase agreement with Petrohawk pursuant to which Petrohawk has agreed to a cash investment of $60,000,000 in our common stock, warrants and a convertible note. Subject to approval by our shareholders, we will receive $25,000,000 for the issuance of 15,151,515 shares of our common stock and five-year common stock purchase warrants exercisable at a price of $1.65 per share. Additionally, we will issue a $35,000,000 convertible note that will be an unsecured five-year obligation and after two years will be convertible by the holder into our common stock at a conversion price of $2.00 per share. Interest only will be payable under the note in quarterly installments at the rate of 8% per annum. The full amount of the principal and accrued and unpaid interest will be payable on the fifth anniversary of the date of the note. Future use of these proceeds would include paying off the existing outstanding debt, acquisitions of oil and gas properties, future development and exploitation of existing and acquired oil and gas properties and exploration activity.

Long Term Liquidity and Capital Resources

We have no material long-term commitments associated with our capital expenditure plans or operating agreements. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. The level of capital expenditures will vary in future periods depending on the success we have with our exploratory drilling activities in future periods, gas and oil price conditions and other related economic factors. The following tables show our contractual obligations and commitments.

		Payments Due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Long Term Debt (1)	$ 13,919,147	$ 515,263	$ 13,403,884	$	$
Operating Leases (2)	93,848	72,351	21,497		
Other (3)	37,500	37,500			
Total cash obligations	$ 14,050,495	$ 625,114	$ 13,425,387	$	$

(1) $13,851,577 represents principal and interest related to our current credit agreement with a commercial bank. For further information please refer to **Item 8. Financial Statements and Supplementary Data, Note 4, <u>LONG-TERM DEBT</u>.**

(2) Represents amounts due under current operating lease agreements including the office rental agreement.

(3) Represents amounts due under a financial advisory agreement.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

Other Commercial Commitments	Total	Amount of Commitment Expiration per Period Less than 1 year	1-3 years	4-5 years	After 5 years
Standby letters of credit	$ 176,500	$ 176,500			

The letters of credit were issued in connection with our operations for such items as production tax and drilling requirements with various state agencies and utility deposits.

We currently have no sources of liquidity or financing that are provided by off-balance sheet arrangements or transactions with unconsolidated, limited purpose entities.

Plan of Operation for 2004

Assuming the Petrohawk transaction is not consummated, for the year 2004 we expect to fund our capital requirements from net cash flow from operations (after general and administrative expense and interest expense). We project our 2004 capital expenditure to be approximately $5.0 million. The areas and amounts of concentration for the capital program will be:

West Edmond Hunton Lime Unit, Oklahoma - $2.9 million

Lapeyrouse Field, Terrebonne Parish, Louisiana - $.8 million

West Broussard Prospect, Lafayette Parish, Louisiana - $.8 million

McIntosh County, Oklahoma - $.2 million

Brookshire Dome Area, Waller County, Texas - $.2 million

Other - $.1 million

We are projecting our cash flows from operations to be approximately $7.5 million based on an average natural gas price of $4.02 per Mcf, as adjusted for basis differentials, and an average spot crude oil price of $24.95 per barrel and average net daily production of 9.2 MMcfe. Any proceeds from the sale or reduction of our working interests in certain prospects are not considered in our cash flow projections. As with any projection, the timing and amounts can vary. Generally, funds must be advanced within thirty days or less after our election to participate in the drilling of a well.

Our planned capital expenditures and/or administrative expenses could exceed those amounts budgeted and could exceed our cash from all sources. While our projected cash expenditures may be as projected, cash flow from operations could be unfavorably impacted by lower-than-projected commodity prices and/or lower than projected production rates. Conversely, higher-than-projected commodity prices would favorably impact our projected cash flow from operations. If our expected cash flow is less than projected it may be necessary to raise additional funds. Possible additional sources of cash could be provided from the following:

1) We have approximately 375,725 callable common stock purchase warrants outstanding exercisable at a price of $7.50 per share. We are able to call these warrants at any time after our common stock has traded on Nasdaq at a market price equal to or exceeding $10.00 per share for 10 consecutive days which was achieved in July 2000. It is our intent to call all of these warrants at such time, if and when, the cash is needed to fund capital requirements. We will receive proceeds equal to the exercise price times the number of shares which are issued from the exercise of warrants net of commission to the broker of record, if any. We could realize net proceeds of approximately $2,814,500 from the exercise of all of these warrants. There is no assurance that any warrants will be exercised or that we will ever realize any proceeds from the $7.50 warrant calls. However, due to current market conditions and the current price of our stock, it is not probable that we will call these warrants in 2004.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

2) We may seek mezzanine financing, if available, on terms acceptable to us. Mezzanine financing usually involves debt with a higher cost of capital as compared to conventional bank financing. We would seek mezzanine financing in the range of $1,000,000 to $5,000,000. We would seek to use this means of financing in the event that a particular acquisition or project did not have sufficient proved producing reserve collateral to support a conventional bank loan.

3) We may realize higher than projected cash flow from oil and gas wells to be drilled, if found to be productive. We own working interests in wells that are currently producing and in additional wells, which are currently drilling or scheduled to be drilled in 2004.

If the above additional sources of cash are insufficient or are unavailable on terms acceptable to us, we will be compelled to reduce the scope of our business activities. If we are unable to fund planned expenditures within a thirty to sixty-day period after a well is proposed for drilling, it may be necessary to:

1) Forfeit our interest in wells that are proposed to be drilled;

2) Farm-out our interest in proposed wells;

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

3) Sell a portion of our interest in proposed wells and use the sale proceeds to fund our participation for a lesser interest; or

4) Reduce general and administrative expenses.

Should our future projected capital expenditures be reduced by lower sources of cash flow or cash requirements for reduction of our credit facility, our potential growth rate from our exploitation and exploration activities could be materially impacted. An alternative action to maintain our growth potential would be the acquisition of existing reserves with the use of debt and equity instruments.

Our long-term goal is to grow by accumulating oil and gas reserves through exploitation of our existing assets, acquisitions and/or exploratory drilling. In the event we cannot raise additional capital, or the industry market is unfavorable, we may have to slow or alter our long-term goal accordingly.

These are forward looking statements that are based on assumptions, which in the future may not prove to be accurate. Although we believe that the expectations reflected in such forward looking statements are based on reasonable assumptions, we can give no assurance that our expectations will be achieved.

Critical Accounting Policies

We rely on certain accounting policies in the preparation of our financial statements. Certain judgments and uncertainties affect the application of such policies. The critical accounting policies which we use are as follows:

- Use of estimates
- Oil and gas properties
- Derivative instruments and hedging activity
- Stock option compensation

Certain accounting principles are employed in the adherence and implementation of these policies along with management judgments. We will address each policy and how certain judgments and/or uncertainties could materially impact these policies.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

Use of Estimates - The preparation of the our consolidated financial statements in conformity with generally accepted accounting principles requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The estimates include oil and gas reserve quantities, which form the basis for the calculation of amortization and impairment of oil and gas properties. We emphasize that reserve estimates are inherently imprecise and that estimates of more recent discoveries are more imprecise than those for properties with long production histories. Actual results could materially differ from these estimates. Volatility in commodity prices also impacts reserve estimates since future revenues from production may decline significantly if there is a material decrease in natural gas and/or crude oil prices from the previous reserve estimation date, which is at each quarter end.

Oil and gas properties - We account for our oil and gas producing activities using the full cost method of accounting as prescribed by the SEC. Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general corporate costs are expensed as incurred. In general, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded. Amortization of evaluated oil and gas properties is computed on the units of production method based on all proved reserve quantities, on a country-by-country basis. The net capitalized costs of evaluated oil and gas properties (full cost ceiling limitation) are not to exceed their related estimated future net revenues discounted at 10%, and the lower of cost or estimated fair value of unevaluated properties, net of tax considerations. Unevaluated oil and gas properties are assessed at least annually for impairment either individually or on an aggregate basis. Unevaluated leasehold costs, including brokerage costs, are individually assessed quarterly based on the remaining primary term of the leasehold. In 2003, unevaluated leasehold costs and related brokerage fees of $1,705,998 were transferred to U.S. evaluated costs, or the full cost pool. For the remaining costs, which includes seismic and geological and geophysical primarily related to Jackson County Texas, historically we have estimated reserve potential for the unevaluated properties using comparable producing areas or wells and risk that estimate by 50-75%. As mentioned previously in *Use of Estimates*, reserve estimations are more imprecise for new or unevaluated areas. Consequently, should certain geological conditions or factors exist, such as reservoir depletion, reservoir faulting, reservoir quality etc., but unknown to us at the time of our assessment, a materially different result could occur.

For 2003, it was the Company s desire to have an industry partner or partners with geotechnical expertise to study and further evaluate the seismic in order to fully evaluate the potential of the areas. Even though discussions with third parties were conducted, no arrangements were finalized in 2003. Since no significant internal evaluation activity occurred in 2003, the Company believed it inappropriate to apply the same methodology used in prior years for its assessment of the Jackson County costs, which represents an average 20% working interest in 286 square miles of proprietary seismic and related interpretational data. At December 31, 2003, the Company believed it more appropriate, due to the previously discussed circumstances and events with respect to Jackson County, to assess impairment based on the estimated value of the seismic data if sold or exchanged for other seismic data The assessment resulted in an impairment of $1,627,116 and the resulting impairment was transferred to U.S. evaluated costs and will be subject to amortization.

Derivative instruments and hedging activity We use derivatives in a limited manner to protect against commodity price volatility. Effectively, we sell a portion of our natural gas and crude oil based on a NYMEX based price with a set floor (bottom) and ceiling (top) price or a range. Our derivatives are recorded on the balance sheet at fair value and changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, depending on the type of transaction. Typically, our derivative contract will consist of cash flow hedge transaction in which it hedges the variability of cash flow related to a forecasted transaction. Changes in the fair value of these derivative instruments are recorded in other comprehensive income and reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The fair value of these contracts may vary materially with the fluctuations of natural gas and crude oil prices. However, the fluctuation in fair value will be offset by the actual value received from the hedged volume.

Stock option compensation - Subsequent to December 31, 2002, we adopted Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (SFAS 123) and related interpretations in accounting for our employee and director stock options. Under SFAS No. 123, the fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model. As allowed by Statement of Financial Accounting Standards No. 148 *Accounting for Stock-Based Compensation Transition and Disclosure,* an amendment to SFAS 123, certain transitional alternatives were available for a voluntary change to the fair value based method of accounting for stock-based employee compensation if adopted in a fiscal year beginning before December 16, 2002. We adopted the *prospective method* which applies prospectively the fair value recognition method to all employee and director awards granted, modified or settled after the beginning of the fiscal year in which the fair value based method of accounting for stock-based compensation is adopted, or in this case January 1, 2003.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

Comparison of Results of Operations

Year ended December 31, 2003 and Compared to Year ended December 31, 2002

We had net income of $967,497 for the twelve months ended December 31, 2003 compared to a net loss of ($6,881,612) for the same period ended 2002. A significantly higher natural gas and crude oil price environment and lower operating expenses were the primary reasons for the increase in net income. The increase was partially offset by a decrease in our oil and gas production and higher general and administrative expenses during the first nine months of this year when compared to same period for last year. Our results of operations for 2002 included a fourth quarter full cost ceiling impairment of $5,163,689.

The following table summarizes key items of comparison and their related increase (decrease) for the twelve months ended December 31 for the periods indicated.

In Thousands	Years Ended December 31, 2003	2002	$ - Increase (Decrease)	% - Increase (Decrease)
Net income (loss)	$ 967.5	$ (6881.6)	$ 7,849.1	(114)%
Oil and gas sales	12,276.5	9,244.5	3,032.0	33%
Field service income	648.2	403.3	244.9	61%
Operating expense	2,404.9	2,772.2	(367.3)	(13)%
Production tax expense	769.1	532.8	236.3	44%
Field service expense	185.3	195.4	(10.1)	(5)%
G&A expense	3,082.6	2,209.9	872.7	39%
Depletion Full cost	4,671.1	4,911.0	(239.9)	(5)%
Depreciation Field service and other	186.5	209.5	(23.0)	(11)%
Impairment expense	129.3	5,163.7	(5,034.4)	(97)%
Interest expense	476.1	558.3	(82.2)	(15)%
Income tax provision	(24.0)		(24.0)	
Production:				
Natural Gas Mcf	1,859.1	2,249.4	(390.3)	(17)%
Crude Oil Bbl	128.8	124.7	4.1	3%
Natural Gas Equivalent Mcfe	2,631.9	2,997.6	(365.7)	(12)%
$ per unit:				
Ave gas price per Mcf	$ 4.71	$ 2.91	$ 1.80	62%
Ave oil price per Bbl	27.36	21.68	5.68	26%
Ave operating expense per Mcfe	.91	.92	(.01)	(1)%
Ave production tax expense per Mcfe	.29	.18	.11	64%
Ave G&A per Mcfe	1.17	.74	.43	59%
Ave Depl per Mcfe	1.77	1.64	.13	8%

Oil and gas sales:

For the twelve months ended December 31, 2003, oil and gas sales increased $3,031,965, or 33%, from the same period in 2002, to $12,276,495. The increase for the twelve months was a direct result of higher natural gas and crude oil prices. Lower natural gas inventory levels and normal to above-normal winter demand in the first quarter contributed significantly to the higher natural gas prices. Lower national storage levels, supply uncertainty due to global events and a weaker U.S. dollar, which impacts the OPEC basket price, favorably impacted crude oil prices. The higher commodity prices resulted in an increase in oil and gas revenues of $4,077,702, with higher natural gas prices comprising 82% of the increase. However, lower natural gas volume for the twelve months ended December 31, 2003, as compared to the same period in 2002, partially offset this increase. Our natural gas production was 17% lower when compared to the same period in 2002. The lower natural gas and crude oil production was primarily due to natural production decline associated with our South Texas, Brookshire, Lapeyrouse and Oklahoma coalbed methane properties. Lower natural gas production volumes resulted in a reduction to natural gas sales of $1,134,855. Our crude oil production volume for the twelve months ended December 31, 2003 was 3% higher when compared to the same period in 2002. The increase in production was a result of our drilling activity in the Brookshire Dome, Texas properties and drilling and recompletion activity on the WEHLU, Oklahoma properties.

Hedging:

Generally, we sell our natural gas and crude oil to various purchasers on an indexed-based or spot price. The indices for natural gas are generally affected by the NYMEX Henry Hub spot prices while the posted prices for crude oil are generally affected by the NYMEX-Crude Oil West Texas Intermediate prices. From time to time, we use hedges on a limited basis to lessen the impact of price volatility. Hedges covered approximately 28% of our production on an equivalent MMbtu basis for the year ended December 31, 2003. For the twelve months ended December 31, 2003, the average sales price received for our natural gas was reduced by approximately $.59 per Mcf from our natural gas hedges and the average sales price received for our crude oil was reduced by approximately $1.80 per Bbl from our crude oil hedges. For further discussion please refer to **Item 8. Financial Statements and Supplementary Data, Note 7,DERIVATIVE AND HEDGING ACTIVITIES.**

Based on our natural gas production for the twelve months ended December 31, 2003, a decline in the average natural gas price realized by Beta of $1.00 per Mcf would have resulted in an approximate $1.3 million reduction in net income before income taxes.

Operating and production tax expenses:

Operating expenses, excluding production taxes, decreased $367,256, or 13%, to $2,404,897 for the twelve months ended December 31, 2003 compared to the same period for 2002. The decrease was primarily due to lower operating expense associated with the Brookshire Dome, Texas properties, the Peace Creek and Zenith Field, Kansas properties and the 2002 divestment of certain low margin non-core properties. Lower expenses in the Brookshire Dome area were primarily due to lower salt water disposal expense as a result of injection well availability and lower workover expense in 2003 on the Wade Crawford #1 and Kathleen Pickett #1.

Production tax expense increased $236,320, or 44%, for the twelve months ended December 31, 2003 as compared to the same period ended in 2002, due to higher natural gas and crude oil revenues. Production taxes are generally assessed as a percentage of gross oil and/or natural gas sales.

General and administrative expense:

General and administrative expense for the twelve months ended December 31, 2003 increased $872,718, or 39%, to $3,082,605 compared to $2,209,887 for the same period in 2002. The increase was due primarily to the following items:

Description		**2003 increase over 2002**
Bonus related to 2002 executive hiring	$	400,000
Accrued 2003 employee bonuses		238,079
Compensation expense from stock options		237,130
Directors fees		103,500
Reserve for bad debt expense		(150,791)
Total	$	827,918

The $400,000 executive bonus related to the hiring of a new chief executive officer in late 2002 and was paid in the first and third quarters of 2003. Bonuses approved by our Compensation Committee were awarded to the employees for 2003 but were not paid until February 2004 and accordingly were accrued in 2003. Compensation expense from stock options is the expense related to the issuance of common stock options issued to employees and directors during 2003. On January 1, 2003, we adopted SFAS 123 (for further discussion, please refer to **Item 8. Financial Statements and Supplementary Data,Note 8. STOCKHOLDERS EQUITY**) and now recognize compensation expense based on the fair value of the stock options granted. Directors fees increased in 2003 primarily due to the increased activity related to the proposed Petrohawk transaction in the fourth quarter of 2003. In 2002, we recorded a reserve for bad debt expense related to the uncertainty of recoupment of a portion of a gas contracts settlement. There was no comparable expense in 2003.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

At December 31, 2003, we had approximately $245,000 of deferred costs associated with the pending Petrohawk transaction. Should we not consummate the Petrohawk transaction, these costs would be reflected in our general and administrative cost at that time. These deferred costs were recorded as a reduction to our paid in capital at December 31, 2003.

Depreciation and amortization expense:

Depletion and depreciation expense decreased $262,975, or 5%, from the same period in 2002 to $4,857,597 for the twelve months ended December 31, 2003. Depletion associated with evaluated oil and gas properties comprised 90% of the decrease. Depletion for oil and gas properties is calculated using the Unit of Production method, which essentially amortizes the capitalized costs associated with the evaluated properties based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Lower production volumes for 2003, as compared to 2002, and a lower depletion rate for the fourth quarter due a significant increase in our December 31, 2003 reserves from our December 31, 2002 proved reserves were the primary reasons for the decrease in depletion expense. However, the total decrease in depletion expense was partially offset due primarily to a decrease in our December 31, 2002 proved reserves related to our West Broussard prospect, which increased our depletion rate per Mcfe for the first nine months of 2003 to $1.90 as compared to $1.44 for the same period in 2002. Depreciation expense for other assets includes depreciation associated with the gathering assets, which is calculated on a unit of revenue method. The unit of revenue method amortizes the capitalized costs associated with the gathering assets based on the ratio of gross actual revenues for the current period to the total remaining gross revenues for the gathering assets. Depreciation expense for the twelve month periods ended December 31, 2003 and 2002 was $186,536 and $209,540, respectively.

Full cost ceiling impairment expense:

At December 31, 2002, we recorded a non-cash impairment charge of $5,163,689 on our U.S. domestic evaluated properties due to the transfer of $4,883,031 from unevaluated properties related to our Jackson County, Texas area. Additionally, our proved reserves decreased in the fourth quarter of 2002 due to the reclassification of the proved undeveloped reserves associated with the West Broussard prospect, to a less certain reserve category. There was no comparable impairment for our U.S. domestic evaluated properties in 2003.

In the fourth quarter of 2003, the Company transferred 100% of the costs associated with a drilling concession in West Queensland Australia in which the Company owns a 25% working interest to our foreign evaluated properties. The concession expired at December 31, 2003 and the operator of the concession has applied for a re-extension but at this date no formal extension has been granted by the Australian government. The prospect remains active but due to the uncertainty for the renewal of the concession the Company elected to charge 100% of the costs to impairment expense in 2003. The amount transferred and impaired was $129,279.

Interest expense:

Interest expense decreased for twelve months ended December 31, 2003, compared to the same period 2002, as a result of lower interest rates and a lower outstanding debt balance.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

Year ended December 31, 2002 and Compared to Year ended December 31, 2001

We had a reported net loss of ($6,881,612) for the year ended December 31, 2002 compared to a net loss of ($9,046,084) for the same period ended 2001. Our results of operations for 2002 included a fourth quarter full cost ceiling impairment of $5,163,689, net of income tax while our 2001 results of operations included a full cost ceiling impairment of $9,950,308, net of income tax. Lower commodity prices and production volumes also contributed to the net loss for 2002.

The following table summarizes key items of comparison and their related increase (decrease) for the twelve months ended December 31 for the periods indicated.

	Years Ended December 31,		$ - Increase	% - Increase
In Thousands	**2002**	**2001**	**(Decrease)**	**(Decrease)**
Net income (loss)	$ (6,881.6)	$ (9,046.1)	$ 2,164.5	(24)%
Oil and gas sales	9,244.5	12,788.1	(3,543.6)	(28)%
Field service income	403.3	868.4	(465.1)	(54)%
Operating expense	2,772.2	2,589.7	182.5	7%
Production tax expense	532.8	879.5	(346.7)	(39)%
Field service expense	195.4	339.3	(143.9)	(42)%
G&A expense	2,209.9	2,679.1	(469.2)	(18)%
Depletion Full cost	4,911.0	4,858.4	52.6	1%
Depreciation Field service and Other	209.5	318.5	(109.0)	(34)%
Impairment expense	5,163.7	13,805.0	(8,641.3)	(63)%
Interest expense	558.3	867.8	(309.5)	(36)%
Income tax (provision) benefit		3,504.4	(3,504.4)	
Production:				
Natural Gas Mcf	2,249.4	2,512.5	(263.1)	(10)%
Crude Oil Bbl	124.7	114.3	10.4	9%
Natural Gas Equivalent Mcfe	2,997.6	3,198.3	(200.7)	(6)%
$ per unit:				
Ave gas price per Mcf	$ 2.91	$ 3.97	$ (1.06)	(27)%
Ave oil price per Bbl	21.68	24.72	(3.04)	(12)%
Ave operating expense per Mcfe	.92	.81	.11	14%
Ave production tax expense per Mcfe	.18	.27	(.09)	(33)%
Ave G&A per Mcfe	.74	.84	(.10)	(12)%
Ave Depl per Mcfe	1.64	1.52	.12	8%

Oil and gas sales:

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

For the year ended December 31, 2002, oil and gas sales decreased $3,543,585 or 28%, from the year ended 2001, to $9,244,530. The decrease resulted from lower commodity prices and lower natural gas production. The lower commodity prices resulted in a decrease in revenue of approximately $2,758,573 or 78% of the total decrease from 2001. Lower natural gas prices comprised 86% of the total price decrease with lower crude oil prices accounting for the remaining 14%. Lower natural gas production volumes resulted in lower 2002 revenues, when compared to 2001, of $1,043,349 partially offset by higher 2002 crude oil production. The increase in 2002 crude oil production, from 2001 production, resulted in increased revenues of $258,338. Natural gas sales volumes were lower for the twelve months ended December 31, 2002 compared to the same period ended 2001, primarily due to lower production in our South Texas shallow Frio wells and West Cameron Block 49 wells partially offset by production from the T. Cenac #1 well, located in the Lapeyrouse field, Terrebonne Parish, Louisiana. The lower production was due to natural decline in the South Texas wells and water production in the West Cameron Block 49 wells, which were reworked and restored to production late in the third quarter of 2002. Increased crude oil production was primarily due to new production associated with our exploration activity in the Brookshire Dome area in Waller County, Texas and the T. Cenac #1.

Hedging:

Generally, we sell our natural gas to various purchasers on an index-based price. These indices are generally affected by the NYMEX Henry Hub spot price. We use hedges on a limited basis to lessen the impact of price volatility. Hedges covered approximately 54% of our production on an equivalent MMbtu basis for the year ended December 31, 2002. Based on our natural gas production for the twelve months ended December 31, 2002, a decline in the average natural gas price realized by Beta of $1.00 per Mcf would have resulted in an approximate $2.1 million reduction in net income before income taxes.

Operating and production tax expenses:

Operating expenses, excluding production taxes, increased $182,435, or 7%, to $2,772,153 for the year ended December 31, 2002 compared to the same period for 2001. The increase was related to our Brookshire Dome, Waller County, Texas properties, in which activity commenced in the last half of 2001. 2002 production tax expense decreased $346,708 from 2001 due to lower oil and gas revenues. Production taxes are generally assessed as a percentage of gross oil and/or gas revenues received.

General and administrative expense:

General and administrative expenses for the twelve months ended December 31, 2002 decreased approximately $469,234, or 18%, to $2,209,887 compared to $2,679,121 for the same period in 2001. The decrease was primarily due to lower personnel costs, including salaries from personnel reductions, outside services, legal, travel and insurance expense. Additionally, the twelve-month period ended December 31, 2001 included a non-recurring charge of $205,415 relating to a settlement of a gas contract dispute. General and administrative expense for 2002 included non-recurring items of 1.) Executive separation compensation of approximately $157,000, 2.) $50,000 executive signing bonus related to our new President and 3.) Bad debt expense of $155,000 related to the recoupment of a portion of the gas contract settlement previously discussed.

Depreciation and amortization expense:

Depletion and depreciation expense decreased $56,325, or 1%, from the same period in 2001 to $5,120,572 for the twelve months ended December 31, 2002. Depletion associated with evaluated oil and gas properties increased $52,668 when compared to 2001. Depletion for oil and gas properties is calculated using the Unit of Production method, which essentially amortizes the capitalized costs associated with the evaluated properties based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Due to a decrease in our proved reserves related to the West Broussard prospect, as previously discussed, our per Mcfe depletion rate for the twelve months ended December 31, 2002 was $1.64 compared to $1.52 for the same period in 2001. For the twelve months ended December 31, 2002, depreciation expense related to other assets decreased $108,993 from the same period in 2001 to $209,540. The decrease was related to the depreciation expense associated with the gathering assets, which is calculated on a unit of revenue method. The unit of revenue method amortizes the capitalized costs associated with the gathering assets based on the ratio of gross actual revenues for the current period to the total remaining gross revenues for the gathering assets. Therefore, the lower gross gathering revenues for the twelve months ended December 31, 2002 resulted in lower depreciation expense for the period.

Full cost ceiling impairment expense:

At December 31, 2002, we recorded a non-cash impairment charge of $5,163,689 on our U.S. domestic evaluated properties due to the transfer of $4,883,031 from unevaluated properties related to our Jackson County, Texas area. Additionally, our proved reserves decreased in the fourth quarter of 2002 due to the reclassification of the proved undeveloped reserves associated with the West Broussard prospect, to a less certain reserve category. The average prices used for the reserve estimation at December 31, 2002 were $4.84 per Mcf for natural gas and $29.53 per barrel for crude oil. In 2001, the total capitalized costs for our U.S. evaluated properties full cost pool exceeded the net realizable value of the properties and, accordingly, impairment write-downs of $7,034,925 and $6,770,110, were recorded in the three-month periods ended December 31, 2001 and September 30, 2001, respectively. The impairments were due mainly to the significant decline in the price of natural gas and crude oil from December 31, 2000 and higher future operating expenses regarding production on the older properties. The average prices used in the determination of the net realizable value at December 31, 2001 and September 30, 2001 were $2.65 and $2.20 per Mcf, respectively, for natural gas and $18.17 and $23.50 per barrel, respectively, for crude oil. The prices used at December 31, 2000 for the impairment test were $10.14 per Mcf for natural gas and $26.06 per barrel for crude oil.

Interest expense:

Interest expense decreased for twelve months ended December 31, 2002, compared to the same period 2001, as a result of lower interest rates.

In 2003, we saw an improvement in our overall financial condition due to: 1.) an increase in our cash flow provided

Income Taxes

As of December 31, 2003, we had available, to reduce future taxable income, a U.S. federal regular net operating loss (NOL) carryforward of approximately $23,627,576, and a U.S. federal alternative minimum tax NOL carryforward of approximately $21,255,782, which expire in the years 2018 through 2023. Utilization of the tax net operating loss carryforward may be limited in the event a 50% or more change of ownership occurs within a three-year period. The tax net operating loss carryforward may be limited by other factors as well. We also had various state NOL carryforwards totaling approximately $5,311,670 at December 31, 2003, with varying lengths of allowable carryforward periods ranging from five to 20 years and can be used to offset future state taxable income. However, if we consummate the proposed Petrohawk transaction, the amount of the NOL carryforwards that we will be able to use in any one year will be significantly restricted. This is because Petrohawk will own approximately 55% of our outstanding common stock, if the transaction is consummated, resulting in a change of control. We had no deferred income taxes at December 31, 2003.

Related Party Transactions

In 2001, the Company entered into an Exploration and Development Area of Mutual Interest Agreement in Fremont County, Wyoming with a director of the Company. The Company purchased certain geology and lease acreage approximating 1,627 acres in a prospect located therein for $154,800. The Company acquired a 75% working interest with the director retaining a 25% working interest and up to a 5% overriding royalty interest. All future exploration and development costs will be shared accordingly with the Company being responsible for 75% and the director responsible for 25% of such costs. During 2001, the Company incurred additional costs of approximately $166,600. In connection with the review of its unevaluated properties for impairment, the Company recorded an impairment of $127,229 based on remaining lease term.

Mr. Robert E. Davis, Jr., director and Chairman of the Company s Board of Directors, has overriding royalty interests in certain of the Company s oil and gas properties, which were acquired from Red River Energy, LLC (Red River) in September 2000. Mr. Davis, former Executive Vice President and Chief Financial Officer of Red River, received the overriding royalty interests as part of his compensation while employed at Red River, prior to its merger with the Company. Mr. Davis received approximately $49,800 in royalty income from Beta properties during 2003.

Director Rolf N. Hufnagel, director since June 20, 2003, and his wife have overriding royalty interests in certain of our oil and gas properties that were acquired from Red River in September 2000. Mr. Hufnagel received the overriding royalty interests as part of his compensation while employed at Red River. Mr. Hufnagel and his wife, collectively, received approximately $136,300 in royalty income from Beta properties during 2003.

Impact of Recently Issued Standards

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51* and revised this interpretation in December 2003 (FIN 46). FIN 46 requires the consolidation of variable interest entities by their primary beneficiary if the variable interest entities do not effectively disperse risks among the parties involved. Previously, entities were generally consolidated by an enterprise when it had a controlling financial interest through ownership of a majority of voting interest in the entity. The adoption of FIN 46 had no impact on our financial position or results of operations.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS 149). SFAS 149 is intended to result in more consistent reporting of contracts as either freestanding derivative instruments subject to SFAS 133 in its entirety, or as hybrid instruments with debt host contracts and embedded derivative features. SFAS 149 was effective for contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003. The adoption of SFAS 149 had no impact on our financial position or results of operations.

On May 15, 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS 150). SFAS 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. SFAS 150 must be applied immediately to instruments entered into or modified after May 31, 2003, and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. Early adoption of SFAS 150 is not permitted. The adoption of SFAS 150 had no impact on our financial position or results of operations.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

We are exposed to market risk related to adverse changes in oil and gas prices. Our oil and gas revenues can be significantly affected by volatile oil and gas prices. This volatility can be mitigated through the use of oil and gas derivative financial hedging instruments. Through the third quarter of 2003, we hedge a portion of our production using costless collars and swaps and we may use such instruments in the future to hedge our production. At December 31, 2002, the fair value of these derivatives was a liability of $702,417. Based on the actual production for the twelve months ended December 31, 2003, approximately 30% of our natural gas production and approximately 23% was hedged for 2003. At December 31, 2003, we had no outstanding hedges due to a projected strong market for both natural gas and crude oil. For more information please refer to **Item 8. Financial Statements and Supplementary Data, Note 7. DERIVATIVE AND HEDGING ACTIVITIES**.

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from short-term rates, mainly LIBOR-based on borrowing from our commercial bank. At December 31, 2003, all of our outstanding debt was at variable rates. This volatility could be mitigated through the use of financial derivative instruments. Currently, we do not have any derivative financial instruments in place to mitigate this potential risk. Based on a 10% increase or decrease in interest rates, our interest expense and net income would have increased or decreased by approximately $45,500 for 2003 and approximately $49,600 for 2002.

Item 8. **Financial Statements and Supplementary Data.**

Our financial statements and supplementary financial data, which begin on page F-1, are included elsewhere in this report.

Item 9. **Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

On May 5, 2003, we appointed Ernst & Young, LLP (EY) as independent auditors to perform the audit of our financial statements for fiscal year 2003. The appointment was effective June 20, 2003 with the ratification by our shareholders. The decision was made by our audit committee of our board of directors and approved by the entire board. It was our desire and need to have independent auditors with an office and presence in Tulsa, Oklahoma where our corporate office is located. Our prior auditors, HEIN & Associates LLP (HEIN), do not maintain a Tulsa office and the HEIN representatives with whom we dealt were located in Orange, California. HEIN remained our independent auditors until June 20, 2003.

There were no disagreements with HEIN on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of HEIN, would have caused it to make reference thereto in its report on our financial statements for such time periods. Also during those time periods, there were no reportable events as such term is used in Item 304(a)(1)(v) of Regulation SK.

Item 9A. **Controls and Procedures**

Based on their evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report on Form 10-K are effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

During the fourth fiscal quarter of the fiscal year covered by this report on Form 10-K, there have been no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART III

Item 10. Directors And Executive Officers Of The Registrant

Director and Executive Officer Information

Directors

Pursuant to the requirements of the Petrohawk purchase agreement, upon the closing, each of Robert E. Davis, Jr., David A. Wilkins, Rolf N. Hufnagel and David A. Melman will resign as directors. Robert C. Stone, Jr., as the sole remaining director, will establish seven as the number of members of the board of directors and will appoint Larry L. Helm, Tucker Bridwell, and James L. Irish III as the designees of Petrohawk, David B. Miller and D. Martin Phillips as the designees of EnCap Investments, L.P., and Floyd C. Wilson to fill the vacancies. These persons will all serve until the next annual meeting of our stockholders. Also in accordance with the terms of the purchase agreement, Floyd C. Wilson will be elected by the board as President, Chief Executive Officer and Chairman of the Board of Beta. The following is information regarding these persons.

Current Beta directors not continuing:

Robert E. Davis, Jr., Chairman of the Board of Directors, age 52, has served as our non-employee, non-officer Chairman since October 2002 and is an independent financial consultant. Previously, Mr. Davis served as Executive Vice President and Chief Financial Officer of Red River Energy, Inc. from 1998 until its acquisition by us in 2000. Prior to co-founding Red River, Mr. Davis served as Executive Vice President and Chief Financial Officer of Carlton Resources Corporation, an oil and gas acquisition company, from 1996 to 1998. From 1994 to1996, he held similar positions at American Central Gas Company, a natural gas gathering and processing company, located in Tulsa, Oklahoma. In 1983, Mr. Davis co-founded Vesta Energy Company, a nationally recognized natural gas marketing company and held various executive positions including President and Chief Executive at Esco Energy, Inc., the parent company of Vesta. During his 25 years in the oil and gas industry, Mr. Davis also served as a CPA with Arthur Young, LLP (now Ernst & Young LLP) and as a commercial lending officer with an Oklahoma bank. Mr. Davis has a Bachelor of Science degree in Finance and Accounting from the University of Oklahoma and is a licensed CPA in the state of Oklahoma.

David A. Wilkins, 43, President and Chief Executive Officer has served in these capacities and as a member of our Board of Directors since October 2002. He has 21 years experience in the oil and gas industry. Previously, he served as Vintage Petroleum Inc. s General Manager of Latin America and as President and General Manager of Vintage Oil Argentina, Inc. from 1997 to 2002. Prior to Mr. Wilkins assignment in Latin America, he served in various engineering positions and ultimately served as Domestic Operations Manager for Vintage from 1993 to 1997. He additionally served as Vice President of Operations for Esco Exploration, Inc. from 1988 to 1992. Mr. Wilkins began his career with Pioneer Production Corporation in 1982. He holds a Bachelor of Science Degree in Petroleum Engineering from Texas Tech University and is a Registered Engineer in the state of Oklahoma.

Rolf N. Hufnagel, age 55, has served as a director since June 2003. Currently Mr. Hufnagel is the principal owner, President and CEO of Crimson Resources, LLC, an independent oil and gas company. He formerly served for a brief period on our board during 2000 following our acquisition of Red River Energy, Inc.,which Mr. Hufnagel cofounded in 1997 and was one of the principal owners, Chairman, President and Chief Executive Officer. Mr. Hufnagel founded and served as Chairman, President and Chief Executive Officer of Carlton Resources Corporation, an oil and gas acquisition company, from 1994 to 1998. From 1986 to 1992, Mr. Hufnagel served as Senior Vice President of RAMCO Oil & Gas, Inc., a privately held property acquisition company. Mr. Hufnagel s experience encompasses over 25 years. Mr. Hufnagel received his Bachelor of Science from Cameron University and his Master of Business Administration from the University of Oklahoma in 1974.

David A. Melman, age 61, has served as a director since June 2003. Currently Mr. Melman is Chairman of the Board and Chief Executive Officer of XCL Ltd., an oil and gas company with interests in the People s Republic of China, having held these positions since 2000. Additionally, Mr. Melman is Chairman of the Board and Chief Executive Officer of Republic Resources, Inc., a Louisiana-based company engaged in the containment and treatment of contaminated ground water, having held these positions since 2001. From 1998 to 2000, Mr. Melman served as the Chief Corporate Officer with Carpatsky Petroleum, Inc., an oil and gas company with interests in the Republic of Ukraine. Mr. Melman holds a Bachelors of Science Degree in Economics and Accounting from Queens College of the City University of New York, a Juris Doctor from Brooklyn Law School and a Master of Laws in Taxation from New York University. Mr. Melman is a member of the Bar of the State of New York.

The one continuing Beta director will be:

Robert C. Stone, Jr., 55, has served as a director since September 2000. Currently, Mr. Stone serves as Senior Vice President/Manager of Energy Lending at Whitney National Bank in New Orleans, Louisiana and has been employed there since 2000. Prior to this position, Mr. Stone was Manager of Energy Technical Services, Energy/Maritime Division at Hibernia National Bank from 1998 to 2000 that included evaluation responsibilities for all syndicated and direct lending E&P segment clients. Mr. Stone has held senior management positions in energy banking for over 20 years, with emphasis on small-cap, public and private producers. His experience includes underwriting and managing senior debt, mezzanine and private equity to the independent sector. He began his banking career as an engineer with First National Bank of Commerce in New Orleans in 1983 after working in various engineering positions with Exxon Company, U.S.A. for seven years. He was also a Founding Governor of the City Energy Club of New Orleans and is involved with many civic organizations in New Orleans where he still resides. Mr. Stone holds both a B.S. and M.S. in Engineering from the University of Houston.

Petrohawk director designees:

Floyd C. Wilson, 57, is an owner, President and Chief Executive Officer of Petrohawk which he founded in June, 2003. Mr. Wilson was the Chairman and Chief Executive Officer of 3TEC Energy Corporation from August 1999 to its merger with Plains Exploration & Production Company in June of 2003. Mr. Wilson founded W/E Energy Company L.L.C., formerly known as 3TEC Energy Company L.L.C. in 1998 and served as its President until August 1999. Mr. Wilson began his career in the energy business in Houston in 1970 as a completion engineer. He moved to Wichita in 1976 to start an oil and gas operating company, one of several private energy ventures which preceded the formation of W/E. Mr. Wilson founded Hugoton Energy Corporation in 1987, and served as its Chairman, President and Chief Executive Officer. In 1994, Hugoton completed an initial public offering and was merged into Chesapeake Energy Corporation in 1998.

David B. Miller, 53, is a Senior Managing Director of EnCap Investments L.P., an investment management and merchant banking firm focused on the upstream and midstream sectors of the oil and gas industry that was founded in 1988. From 1988 to 1996, Mr. Miller also served as President of PMC Reserve Acquisition Company, a partnership jointly owned by EnCap and Pitts Energy Group. Prior to the establishment of EnCap, Mr. Miller served as Co-Chief Executive Officer of MAZE Exploration Inc., a Denver, Colorado, based oil and gas company he co-founded in 1981. Mr. Miller was a director of 3TEC Energy Corporation. from 1999 until June, 2003. Mr. Miller is also a director of Denbury Resources Inc.

D. Martin Phillips, 50, is a Senior Managing Director of EnCap Investments L.P., an investment management and merchant banking firm focused on the upstream and midstream sectors of the oil and gas industry that was founded in 1988. Prior to joining EnCap in 1989, from 1978 to 1989, Mr. Phillips served in various management capacities with NCNB Texas National Bank, including as Senior Vice President in the Energy Banking Group. Mr. Phillips is also a director of Plains Resources, Inc. Mr. Phillips was a director of 3TEC Energy Corporation. from 1999 until June, 2003.

Larry L. Helm, 56, has 30 years of experience in commercial banking. Mr. Helm is currently not employed. He was employed with Bank One Corporation from December 1989 through December 2003. Most recently Mr. Helm served as Executive Vice President of Middle Market Banking from October 2001 to December 2003. From August 1999 to October 2001, he was Chairman of Southern Region Commercial Banking and from April 1998 to August 1999, he served as Executive Vice President of the Energy and Utilities Banking. He served as director of 3TEC Energy Corporation from 2000 to June, 2003.

Tucker Bridwell, 52, has been the President of Mansefeldt Investment Co. since September 1997 and is in charge of the overall supervision and management of more than $100 million in investments. He has been in the energy business in various capacities for over 25 years. Mr. Bridwell served as chairman of First Permian, LLC from 2000 until its sale to Energen Corporation in April 2002. He is a certified public accountant.

James L. Irish III, 59, served as a director of 3TEC Energy Corporation from 2002 until June, 2003. Mr. Irish is currently of counsel with Thompson & Knight, L.L.P., a Texas based law firm. Mr. Irish has been an attorney with Thomson & Knight, L.L.P. serving in various capacities, including Managing Partner, since 1969.

Executive Officers

Officers are appointed to serve until the meeting of the board of directors following the next annual meeting of stockholders and until their successors have been elected and qualified. The following information is provided about our current executive officers:

David A. Wilkins, 43, President and Chief Executive Officer, Director has served in these capacities since October 2002. He has 21 years experience in the oil and gas industry. Previously, he served as Vintage Petroleum Inc. s General Manager of Latin America and as President and General Manager of Vintage Oil Argentina, Inc. from 1997 to 2002. Prior to Mr. Wilkins assignment in Latin America, he served in various engineering positions and ultimately served as Domestic Operations Manager for Vintage from 1993 to 1997. He additionally served as Vice President of Operations for Esco Exploration, Inc. from 1988 to 1992. Mr. Wilkins began his career with Pioneer Production Corporation in 1982. He holds a Bachelor of Science Degree in Petroleum Engineering from Texas Tech University and is a Registered Engineer in the state of Oklahoma.

Joseph L. Burnett, 51, Chief Financial Officer and Secretary, joined Beta in June 2000. He came to Beta with 26 years of oil and gas accounting experience. Most recently, he served American Central Gas Technologies, Inc. as Controller from 1994 to 2000. Prior to working at American Central, Mr. Burnett served at Esco Energy, Inc. for approximately seven years as Vice President/Controller. He served as Treasurer and Director for Trans Atlantic Resources, Inc. from 1982 to 1987. He started his oil and gas career in 1974 at

Skelly Oil (later Getty Oil) in its management trainee program. Mr. Burnett received his Bachelor of Science in Business Administration from Oklahoma State University in 1974 and is a Certified Public Accountant.

It is currently anticipated that, in addition to Floyd C. Wilson, the following persons will become executive officers of Beta after the closing of the Petrohawk transaction:

Stephen W. Herod, 45, is currently employed by Petrohawk which he joined in June 2003. He served as Executive Vice President-Corporate Development for 3TEC Energy Corporation from December 1999 until its merger with Plains Exploration & Production Company in June 2003 and as Assistant Secretary from May 2001 until June 2003. Mr. Herod served as a director of 3TEC from July 1997 until January 2002. Mr. Herod served as the Treasurer of 3TEC from 1999 until 2001. From July 1997 to December 1999, Mr. Herod was Vice President-Corporate Development. Mr. Herod served as President and a director of Shore Oil Company from April 1992 until the merger of Shore with 3TEC on June 30, 1997. He joined Shore s predecessor as Controller in February 1991. Mr. Herod was employed by Conquest Exploration Company from 1984 until 1991 in various financial management positions, including Operations Accounting Manager. From 1981 to 1984, Superior Oil Company employed Mr. Herod as a financial analyst.

Shane M. Bayless, 36, is currently employed by Petrohawk which he joined in June 2003. He was Vice President and Controller of 3TEC from July 2000 until 3TEC s merger with Plains Exploration & Production Company in June 2003. Mr. Bayless served as the Treasurer of 3TEC from March 2001 until June 2003. Prior to joining 3TEC, Mr. Bayless was employed by Encore Acquisition Company as Vice President and Controller from 1998 to 2000. Mr. Bayless worked as the Controller from 1996 to 1998 and as the Accounting Manager from 1993 to 1996 at Hugoton. From 1990 to 1993, Mr. Bayless was an Audit Senior with Ernst & Young LLP. He is a Certified Public Accountant.

Richard K. Stoneburner, 50, is currently employed by Petrohawk which he joined in July 2003. He joined 3TEC in August 1999 and was its Vice President Exploration from December 1999 until its merger with Plains Exploration & Production Company in June 2003. Mr. Stoneburner was employed by W/E Energy Company as District Geologist from 1998 to 1999. Prior to joining W/E Energy, Mr. Stoneburner worked as a geologist for Texas Oil & Gas, The Reach Group, Weber Energy Corporation, Hugoton and, independently through his own company, Stoneburner Exploration, Inc. Mr. Stoneburner has over 25 years of experience in the energy business.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, certain officers and holders of 10% or more of any class of our stock to report to the SEC, by a specified date, initial reports of ownership and reports of changes in ownership of our stock and other equity securities. We believe that during the fiscal year ended December 31, 2003, our directors and executive officers complied with all these filing requirements, based solely on a review of copies of reports filed under Section 16(a) furnished to us and on the written representations of our directors and executive officers except for one delinquent Form 4 filing by Rolf N. Hufnagel pertaining to one transaction for a stock option grant and one delinquent Form 4 filing by David A. Melman pertaining to one transaction for a stock option grant.

Code of Ethics

We have adopted a Code of Ethics that applies to our principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions. We are filing a copy of our Code of Ethics as an Exhibit to this Annual Report on Form 10-K. The Code of Ethics, together with our Code of Conduct applicable to all of our directors, officers and employees will be available on our Internet website at *http://www.betaoil.com* on or before May 4, 2004.

Item 11. Executive Compensation

Summary Compensation Table

The following table sets forth certain information with respect to the compensation of David A. Wilkins, our current Chief Executive Officer, and Joseph L. Burnett, our Chief Financial Officer and Secretary, for services in all capacities to us during the fiscal years ended December 31, 2003, 2002 and 2001. Mr. Wilkins joined Beta on October 21, 2002. None of our other executive officers had an annual salary and bonus in excess of $100,000 paid by us during any such year. No information is given as to any person for any fiscal year during which such person was not an executive officer of us.

		Annual Compensation			Long-Term Compensation Awards	
Name and Principal Position	**Year**	**Salary**	**Bonus**	**Other Annual Compensation (2)**	**Securities Underlying Options**	**Matching Contributions to Simple IRA Retirement Plan**
David A. Wilkins(1) Chief Executive Officer,	2003	$ 160,000	$ 400,000		100,000(3)	$ 8,000
President and Director	2002	$ 32,205	$ 50,000		500,000(4)	$ 966
Joseph L. Burnett Chief Financial Officer	2003	$ 125,000	$ 10,417		100,000(5)	$ 4,060
and	2002	$ 95,000				$ 2,850
Secretary	2001	$ 95,000			25,000(6)	$ 2,850

(1) Effective October 21, 2002, Mr. Wilkins was appointed as our President and Chief Executive Officer and joined our board of directors. Mr. Wilkins compensation includes an annual base salary of $160,000.

(2) Does not include the value of perquisites and other personal benefits because the aggregate amount of such compensation does not exceed the lesser of $50,000, or 10% of the total amount of salary and bonus for any named individual.

(3) Stock options for 100,000 shares of common stock were granted to Mr. Wilkins on December 31, 2003 which are exercisable at $1.90 per share and expire on December 31, 2013.

(4) As partial consideration for the forfeiture of Mr. Wilkins incentive common stock options (vested and unvested) with his former employer, Mr. Wilkins was granted an option to purchase 500,000 shares of our common stock at an exercise price of $1.30 per share.

(5) Stock options for 100,000 shares of common stock were granted to Mr. Burnett on April 22, 2003 which are exercisable at $1.00 per share and expire on April 22, 2009. These options were issued under our Amended 1999 Incentive and Nonstatutory Stock Option Plan.

(6) Stock options for 25,000 shares of common stock were granted to Mr. Burnett on December 24, 2001 which are exercisable at $4.00 per share and expire on December 24, 2006. These options were issued under our Amended 1999 Incentive and Nonstatutory Stock Option Plan.

Stock Options

We use stock options as part of the overall compensation of directors, officers and employees. In the following table, we show certain information with respect to stock options granted in 2003 to the named executive officers.

Option Grants in 2003

Name	Number of securities underlying Options#	Percent of total options granted to employees in 2003(1)	Exercise or base price ($/Sh)		Expiration date	Potential realizable value at assumed annual rates of stock price appreciation for option term 0% ($)		5% ($)(2)		10% ($)(2)	
David A. Wilkins	100,000(3)	25%	$	1.90	12/31/2013	$	7,000	$	119,491	$	302,803
Joseph L. Burnett	100,000(4)	25%	$	1.00	04/22/2009	$	0	$	34,010	$	77,160

(1) Based on a total of 405,500 shares underlying options being granted to certain employees during fiscal 2003.

(2) Caution is recommended in interpreting the financial significance of these figures. The figures are calculated by multiplying the number of options granted times the difference between a future hypothetical stock price and the option exercise price and are shown pursuant to rules of the SEC. These amounts are calculated based on the indicated annual rates of appreciation and annual compounding from the date of grant to the end of the option term. Actual gains, if any, on stock option exercises are dependent on the future performance of the common stock and overall stock market conditions. There is no assurance that the amounts reflected in this table will be achieved.

(3) All options were granted on December 31, 2003 at an exercise price equal to the fair market value of the common stock on the preceding day to date of grant. The closing price of the stock on the date of grant was $1.97 per share. The options have a term of ten years and vest over a three-year period from the date of grant with one third becoming exercisable on the first anniversary of the grant, one third becoming exercisable on the second anniversary of the grant and the remaining one third becoming exercisable on the third anniversary of the grant. Subject to closing of the Petrohawk transaction and subsequent stockholder approval, the option agreements with Mr. Wilkins will be amended to provide that they will be exercisable in full immediately and they will continue to be exercisable through the fifth anniversary of the closing of the Petrohawk transaction even if Mr. Wilkins employment should be terminated. See Terms of the Purchase Agreement Covenants Post-Closing Covenants Amendment of Stock Options.

(4) All options were granted on April 22, 2003 at an exercise price equal to the greater of fair market value of the common stock on that date or $1.00. The options have a term of six years and vest over a three-year period from the date of grant with one-third becoming exercisable on the first anniversary of the grant, one third

becoming exercisable on the second anniversary of the grant and the remaining one third becoming exercisable on the third anniversary of the grant. Subject to closing of the Petrohawk transaction and subsequent stockholder approval, the option agreements with Mr. Burnett will be amended to provide that they will be exercisable in full immediately and they will continue to be exercisable through the fifth anniversary of the closing of the Petrohawk transaction even if Mr. Burnett s employment should be terminated. See Terms of the Purchase Agreement Covenants Post-Closing Covenants Amendment of Stock Options.

The following table shows certain information with respect to stock options exercised in 2003 by Mr. Wilkins and Mr. Burnett and the value of their unexercised stock options at December 31, 2003.

Aggregated Option Exercises in 2003 and Fiscal Year End Option Values

Name	Shares acquired on exercise	Value Realized	Number of securities underlying unexercised options at fiscal year end (#) Exercisable/Unexercisable	Value of unexercised in-the-money options at the fiscal year end ($)(1) Exercisable/Unexercisable
David A. Wilkins(2)	None	None	166,667/433,333	$111,667/$230,333.11
Joseph L. Burnett(3)	None	None	155,000/100,000	$0/$97,000

(1) The value of in-the-money options is equal to the fair market value of a share of common stock at fiscal year end, based on the last sale price of our common stock ($1.97 per share on December 31, 2003), less the exercise price.

(2) As more fully described in the Summary Compensation Table and in the table under Option Grants in 2003 , Mr. Wilkins was granted options covering 100,000 shares of common stock during 2003. In 2002, he was granted options covering 500,000 shares of common stock as discussed below under Employment Agreements, Termination of Employment and Change of Control Agreements.

(3) Mr. Burnett was granted options covering 100,000 shares of common stock during 2003. In 2001, he was granted options covering 25,000 shares of common stock and in 2000 he was granted options covering 30,000 shares of common stock. He was granted 100,000 stock purchase warrants in 2000 as an inducement to accept employment with us.

Employment Agreements, Termination of Employment and Change of Control Arrangements

Effective October 21, 2002, David A. Wilkins was appointed as our President and Chief Executive Officer and joined our board of directors. Mr. Wilkins compensation includes an annual base salary of $160,000 and eligibility for 2003 incentive compensation equal to, and not less than, $64,000, which is 40% of his annual salary. In consideration for the forfeiture of his incentive common stock options (vested and unvested) with his former employer, he received a $50,000 bonus paid upon his commencement of employment and a $250,000 bonus paid on January 2, 2003, a $150,000 bonus paid on July 1, 2003, and a $150,000 bonus paid on January 2, 2004. Upon commencement of his employment, Mr. Wilkins was granted options to purchase 500,000 shares of our stock at an exercise price of $1.30 per share and on December 31, 2003 was granted an option to purchase 100,000 shares at a price equal to $1.90 per share, our common stock closing price on Nasdaq for the preceding day. These options have a term of ten years and vest over a three-year period from the date of grant, with one third becoming exercisable on the first anniversary of the grant, one third becoming exercisable on the second anniversary of the grant and the remaining one third becoming exercisable on the third anniversary of the grant. Subject to closing of the Petrohawk transaction and subsequent stockholder approval, the option agreements with Mr. Wilkins will be amended to provide that they will be exercisable in full immediately and they will continue to be exercisable through the fifth anniversary of the closing of the Petrohawk transaction even if Mr. Wilkins employment should be terminated. Under the terms of the purchase agreement, Petrohawk has agreed to present to our stockholders following the closing a proposal that the amendment of these options and all of the other options held by our employees be approved and to vote its shares in favor of the proposal. See Terms of the Purchase Agreement Covenants Post-Closing Covenants Amendment of Stock Options.

Joseph L. Burnett, our Chief Financial Officer and Secretary, has options and warrants to purchase 255,000 shares of our stock. Mr. Burnett was issued 100,000 warrants in 2000 as an inducement for his employment with us. These warrants are currently exercisable at a price of $8.38 per share and expire May 31, 2005. Also in 2000, Mr. Burnett was granted options to purchase 30,000 shares of our stock at an exercise price of $7.70. These options have a term of five years and vested upon grant. In 2001, Mr. Burnett was granted options to purchase 25,000 shares of our stock at an exercise price of $4.00. These options also have a term of five years and vested upon grant. In 2003, Mr. Burnett was granted options to purchase 100,000 shares of our stock at an exercise price of $1.00. These options have a term of six years and vest over a three-year period from the date of grant, with one third becoming exercisable on the first anniversary of the grant, one third becoming exercisable on the second anniversary of the grant and the remaining one third becoming exercisable on the third anniversary of the grant. Subject to closing of the Petrohawk transaction and subsequent stockholder approval, the option agreements with Mr. Burnett will be amended to provide that they will be exercisable in full immediately and they will continue to be exercisable through the fifth anniversary of the closing of the Petrohawk transaction or until they would have otherwise expired absent termination of employment, whichever is earlier, even if

Mr. Burnett s employment should be terminated. Under the terms of the purchase agreement, Petrohawk has agreed to present to our stockholders following the closing a proposal that the amendment of these options and all of the other options held by our employees be approved and to vote its shares in favor of the proposal. See Terms of the Purchase Agreement Covenants Post-Closing Covenants Amendment of Stock Options.

Compensation of Directors

Employee directors receive no additional compensation for service on the board of directors or any committee thereof. Our bylaws state that our non-employee directors shall not receive any stated salary for their services, but, by resolution of the board of directors, a fixed sum and expense of attendance, if any, may be allowed for attendance at each regular and special meeting of the board of directors. All our directors receive actual expense reimbursements, and we currently pay $1,500 in fees to each of our outside directors per board and committee meeting, including meetings held by teleconference. In 2003, the aggregate of the directors fees to all outside directors was $141,500.

Prior to July 1, 2003, non-employee directors received options to purchase 50,000 shares of our common stock for their initial year of service and 25,000 each year thereafter, if re-elected, on their anniversary dates, provided that options granted to each of these directors could not cover more than 100,000 shares in the aggregate. This policy changed so that effective July 1, 2003, directors receive only annual option grants covering 10,000 shares on the date of the annual meeting but with no cap on the number of shares which may be covered by these options. Prior to July 1, 2003, the option granted to the chairman of the board of directors each year covered an additional 25,000 shares, but effective July 1, 2003, this was reduced to 15,000 additional shares each year. Prior to July 1, 2003, the chairman of the audit committee received an additional 25,000 shares covered by his option each year but this was reduced to 15,000 shares effective July 1, 2003. The exercise price of these options is equal to 110% of the fair market value of the common stock on the date of grant. We maintain directors and officers liability insurance.

In April 2003, Robert E. Davis, Jr. was granted an option, which vested on the grant date, to purchase 14,583 shares of our company stock, with an exercise price of $1.00 per share which expires in April 2013. Additionally in April 2003, an option, which vested on the grant date, to purchase 50,000 shares of our common stock, with an exercise price of $1.00 per share which expires in April 2013, was issued to Mr. Stone for past and present services provided as chairman of our audit committee for the service period of 2001-2003. Additionally, Mr. Stone returned fully vested options covering 50,000 shares with an exercise price of $10.00 per share and 25,000 shares with an exercise price of $5.22 per share. In exchange for the returned options, Mr. Stone received three stock options covering a total of 75,000 shares of common stock which were granted in 25,000 increments at June 30, 2003, September 30, 2003 and December 31, 2003 at exercise prices equal to or greater than 110% of the closing price of the common stock on The Nasdaq Stock Market, or $1.00 per share, whichever was greater on the respective dates of grant. The options vested immediately on the grant dates and have a ten-year life. The exercise prices of the grants ranged from $1.46 to $2.17 per share.

Compensation Committee Interlocks and Insider Participation in Compensation Decisions

From October 21, 2002, when David A. Wilkins was appointed as a director and President and Chief Executive Officer, until June 20, 2003, he was a member of the compensation committee and participated in deliberations concerning executive officer compensation, including his own. On June 20, 2003, Rolf N. Hufnagel, an outside director of Beta, replaced Mr. Wilkins on the compensation committee. The other members of the committee during 2002 and 2003, Robert C. Stone, Jr. and Robert E. Davis, Jr., are outside directors of Beta.

Directors Robert E. Davis, Jr. and Rolf N. Hufnagel have overriding royalty interests in certain of our oil and gas properties. See Certain Relationships and Related Transactions below.

Compensation Committee Report on Executive Compensation

During 2003, the members of the compensation committee were Robert C. Stone, Jr., Robert E. Davis, Jr., outside directors of Beta, and from October 21, 2002 until June 20, 2003, David A. Wilkins, President and Chief Executive Officer. On June 20, 2003, Rolf N. Hufnagel replaced Mr. Wilkins and the compensation committee now consists solely of outside directors.

Report of the Compensation Committee

As the compensation committee of the board of directors, we are responsible for formulating and recommending to the full board of directors the compensation paid to Beta s executive officers, including Mr. Wilkins, the President and Chief Executive Officer. We generally review executive compensation on an annual basis. In reviewing the overall compensation of our executive officers, we consider the following components of executive compensation:

- base salaries;
- stock option grants;
- cash bonuses;
- insurance plans; and
- contributions by Beta to the simple IRA retirement plan.

In establishing the compensation paid to our executives, we emphasize providing compensation that will

- motivate and retain the executives and reward performance;
- encourage the long term success of Beta; and
- encourage the application of prudent decision making processes in an industry marked by volatility and high risk.

Historically, we have evaluated compensation paid to our executive officers based upon the following factors:

the growth in Beta s oil and gas reserves;

the market value of Beta s common stock;

cash flow;

the extent to which the executive officers have been successful in finding and creating opportunities for Beta to participate in drilling or acquisition ventures having quality prospects;

the ability of our executives to formulate and maintain sound budgets for drilling ventures and other business activities;

the overall financial condition of Beta;

the extent to which proposed business plans are met; and

by comparing the compensation packages of our executive officers with the compensation packages of executive officers of other companies similar to Beta.

We do not assign relative weights or rankings to these factors. Instead, we make subjective determinations based upon a consideration of all of these factors.

In establishing base salaries for the executive officers, we have not relied on independent consultants to analyze or prepare formal surveys for us. However, we do make informal comparisons of our executives compensation with the compensation paid to executives of other publicly and privately held companies similar to Beta. We also rely on our general knowledge and experience in the oil and gas industry, focusing on a subjective analysis of each of our executives contributions to Beta s overall performance. In addition, we take into account the fact that we do not provide significant perquisites to our executive officers. While specific performance levels or benchmarks are not used to establish salaries or grant stock options, we do take into account historic comparisons of Beta s performance. With respect to awards of stock options, we attempt to provide the executives with an incentive compensation vehicle that could result in future additional compensation to the executives, but only if the value of our common stock increases for all stockholders. All stock options are granted with exercise prices equal to or greater than the fair market value of the common stock on the date of grant. When awarding stock options, we consider the number of options granted on prior occasions and the length of time between option grants.

As partial consideration for the forfeiture of Mr. Wilkins incentive common stock options (vested and unvested) with his former

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employer, in 2002, Mr. Wilkins was granted an option to purchase 500,000 shares of Beta s stock at an exercise price of $1.30 per share. We also granted Mr. Wilkins an option to purchase 100,000 shares on December 31, 2003 at an exercise price of $1.90 per share. All of these options have a term of ten years and vest over a three-year period from the date of grant, with one third becoming exercisable on the first anniversary of the grant, one third becoming exercisable on the second anniversary of the grant and the remaining one third becoming exercisable on the third anniversary of the grant. We also awarded a $50,000 cash signing bonus to Mr. Wilkins in October 2002 with additional deferred signing bonuses of $250,000 on January 2, 2003, $150,000 on July 1, 2003 and $150,000 on January 2, 2004.

In reviewing the overall compensation offered to Mr. Wilkins for his employment with Beta, we considered Beta s overall financial condition as well as the individual contributions made by Mr. Wilkins. We feel that the stock option awards to our executive officers, including Mr. Wilkins, act as a catalyst to advancing the financial interests of stockholders along with those of management. It is our conclusion that the amount and types of compensation currently being paid to our executive officers are sufficient to motivate them and encourage their efforts to increase the value of Beta for all stockholders.

Provisions of the Internal Revenue Code that restrict the deductibility of certain compensation over one million dollars per year have not been a factor in our considerations or recommendations.

On October 15, 2003, the compensation committee approved and recommended to our board of directors a severance arrangement for all of our employees in connection with the consummation of the Petrohawk transaction. Under this arrangement, all outstanding stock options will vest in full and the options will continue to be exercisable for a period of five years from the date of closing or until they would have otherwise expired absent a termination of employment, whichever is earlier, even if the employment of the option holder is terminated. Under the current option provisions, only a portion of the options are currently exercisable (which amounts increase over time with Beta) and would terminate at the end of 90 days following termination of the employment of the option holder. In addition to the amendment of the employee stock options, each employee will receive a severance payment equal to a stated multiple of his or her monthly salary. Mr. Wilkins and Joseph L. Burnett, our Chief Financial Officer hold options covering 600,000 shares and 155,000 shares, respectively, and will receive severance payments of $160,000 and $125,000, respectively, which equal one year s salary.

Respectfully Submitted,

Robert C. Stone, Jr.

Robert E. Davis, Jr.

Rolf N. Hufnagel

Common Stock Performance Graph

The following common stock performance graph shows the performance of Beta s stock up to December 31, 2003. As required by applicable rules of the SEC, the performance graph shown below was prepared based on the following assumptions:

1. A $100 investment was made in our common stock and each index on July 9, 1999, the date on which our common stock commenced trading on Nasdaq..

2. The indices are weighted daily, using the market capitalization on the previous trading day.

3. If the quarterly interval, based on the fiscal year end, is not a trading day, the preceding trading day is used.

4. All dividends are reinvested on the ex-dividend date.

The indices in the performance graph compare the annual cumulative total stockholder return on our common stock with the cumulative total return of The Nasdaq Stock Market (U.S.) Index and a peer group index comprised of five U.S. companies engaged in crude oil and natural gas operations whose stocks were traded on Nasdaq during the period from July 9, 1999 through December 31, 2003. The companies that comprise the peer group are Brigham Exploration Co. (BEXP), Carrizo Oil & Co., Inc. (CRZO), Cheniere Energy, Inc. (CXY), Edge Petroleum Corp. (EPEX) and Parallel Petroleum Corp. (PLLL). The following information has been provided by Research Data Group.

Total Return Analysis	**7/9/99**	**9/99**	**12/99**	**3/00**	**6/00**	**9/00**	**12/00**	**3/01**	**6/01**	**9/01**	**12/01**	**12/02**	**12/03**
Beta	100.00	106.25	123.97	164.58	181.25	154.17	124.73	117.18	133.33	82.50	81.17	14.33	32.83
NASDAQ	100.00	98.42	145.46	163.30	141.99	130.66	87.49	65.31	76.98	53.40	69.42	47.99	99.61
Peer Group	100.00	102.04	65.25	84.10	107.32	181.88	175.26	160.19	131.50	99.52	103.89	113.84	247.69

Item 12. Security Ownership Of Certain Beneficial Owners And Management

The following table reflects, as of March 1, 2004, the beneficial ownership of our common stock and preferred stock by (i) all persons known by us to be beneficial owners of more than 5% of each class of stock, (ii) each of our directors, (iii) each of the persons who will become a director in connection with the closing of the Petrohawk transaction in accordance with the terms of the Petrohawk purchase agreement if the Petrohawk transaction is approved and consummated (see Director and Executive Officer Information); (iv) each of our executive officers named in the Summary Compensation Table above, and (v) all of our executive officers and directors as a group and provides the percentage of outstanding shares of each class held. The table also shows the number of shares of common stock and the percentage of the outstanding common stock that will be owned by the persons described above and Petrohawk if the issuance of the securities in the Petrohawk transaction is approved and consummated.

Name of Beneficial Owner	Shares of Common Stock Beneficially Owned(1)	Percent of Class(2)	Shares of Common Stock Beneficially Owned After the Issuance of Securities to Petrohawk(1)	Percent of Class After Issuance of Securities to Petrohawk(2)(3)
Robert E. Davis, Jr	364,583(4)	2.91%	364,583(4)	1.31%
Steve A. Antry 11814 S. Sheridan Road Tulsa, OK 74008	1,138,000(5)	9.14%	1,138,000(5)	4.11%
Robert C. Stone, Jr.	180,000(6)	1.43%	195,000(6)(16)	*
David A. Wilkins	166,667(7)	1.32%	600,000(7)	2.12%
Rolf N. Hufnagel	820,000(8)	6.57%	820,000(8)	2.96%
David A. Melman	50,000(9)	*	50,000(9)	*
Joseph L. Burnett	189,333(10)	1.50%	256,000(10)	*
Floyd C. Wilson			25,151,515(15)	66.82%
David B. Miller			25,151,515(13)(14)	66.82%
D. Martin Phillips			25,151,515(13)(14)	66.82%
Larry L. Helm			15,000(16)	*
Tucker Bridwell			15,000(16)	*
James L. Irish III			15,000(16)	*
Petrohawk Energy, LLC 1100 Louisiana, Suite 3650 Houston, Texas 77002			25,151,515(12)	66.82%
EnCap Energy Capital Fund IV, L.P. 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%
EnCap Energy Acquisition IV-B, Inc. 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%
EnCap Energy Capital Fund IV-B, L.P. 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%
EnCap Equity Fund IV GP, L.P. 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%

EnCap Investments L.P. 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%
EnCap Investments GP, L.L.C. 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%
RNBD GP LLC 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%
Gary R. Petersen 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%
Robert L. Zorich 1100 Louisiana, Suite 3150 Houston, Texas 77002			25,151,515(13)(14)	66.82%
All officers and directors as a group	1,770,583(11)	13.73%	2,285,583(17)	6.46%

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* Represents less than 1% of that class of stock outstanding.

(1) Unless otherwise indicated, all shares of stock are held directly with sole voting and investment power. Securities not outstanding, but included in the beneficial ownership of each such person are deemed to be outstanding for the purpose of computing the percentage of outstanding securities of the class owned by such person, but are not deemed to be outstanding for the purpose of computing percentage of the class owned by any other person. The total number includes shares issued and outstanding as of March 1, 2004, plus shares which the owner shown above has the right to acquire within 60 days after March 1, 2004. Information is provided for reporting purposes only and should not be construed as an admission of actual beneficial ownership.

(2) For purposes of calculating the percent of the class outstanding held by each owner shown above with a right to acquire additional shares, the total number of shares excludes the shares which all other persons have the right to acquire within 60 days after March 1, 2004, pursuant to the exercise of outstanding stock options and warrants.

(3) The percentages are based on the assumption that 27,640,322 shares of common stock and 604,271 shares of preferred stock will be outstanding immediately following the issuance of the securities to Petrohawk. The table also assumes that the Petrohawk transaction will be consummated upon the terms of the transaction documents described in this proxy statement.

(4) Includes 114,583 shares of common stock underlying stock options.

(5) Shares held with spouse as community property. Includes 25,000 warrants held on behalf of minor children.

(6) Includes 175,000 shares of common stock underlying stock options.

(7) Represents shares of common stock underlying stock options.

(8) Includes 50,000 shares of common stock underlying stock options.

(9) Represents shares of common stock underlying stock options.

(10) Includes 188,333 shares of common stock before closing the Petrohawk transaction and 255,000 shares of common stock after closing the Petrohawk transaction which are issuable upon exercise of outstanding stock options and warrants.

(11) Total for the 6 persons who were officers or directors prior to the issuance of the securities to Petrohawk. This includes 100,000 shares of common stock underlying stock warrants and 611,250 shares of common stock underlying stock options.

(12) Includes 15,151,515 shares of common stock and warrants to purchase 10,000,000 shares of common stock exercisable within 60 days after the date hereof.

(13) Represents shares owned by Petrohawk. These entities or persons may be deemed to share voting and dispositive control over the shares of common stock owned by Petrohawk. EnCap Energy Capital Fund IV, L.P. and EnCap Energy Acquisition IV-B, Inc., each of which is a member of Petrohawk, have the contractual right to nominate a majority of the members of the board of directors of Petrohawk pursuant to Petrohawk s limited liability company agreement. These two entities are controlled indirectly by David B. Miller, Gary R. Petersen, D. Martin Phillips and Robert L. Zorich. In addition, Mr. Miller and Mr. Phillips are the members of Petrohawk s board of directors. Messrs. Miller, Petersen, Phillips and Zorich are members of RNBD GP LLC which in turn has management control, directly or indirectly, over the other EnCap entities listed on this beneficial ownership table, including EnCap Investments GP, L.L.C., EnCap Investments L.P., EnCap Equity Fund IV GP, L.P., EnCap Energy Capital Fund IV-B, L.P., EnCap Energy Capital Fund IV, L.P. (a member of Petrohawk) and EnCap Energy Acquisition IV-B, Inc. (a member of Petrohawk). All the EnCap entities listed in the preceding sentence, other than the two EnCap entities which are members of Petrohawk, have management control, directly or indirectly, over these two EnCap entities with membership in Petrohawk.

(14) Each of EnCap Energy Capital Fund IV, L.P., EnCap Energy Acquisition IV-B, Inc., EnCap Energy Capital Fund IV-B, L.P., EnCap Equity Fund IV GP, L.P., EnCap Investments L.P., EnCap Investments GP, L.L.C., RNBD GP LLC, David B. Miller, Gary R. Petersen, D. Martin Phillips, and Robert L. Zorich disclaim beneficial ownership of the reported securities in excess of such entity s or person s respective pecuniary interest in the securities.

(15) Represents shares owned by Petrohawk. Floyd C. Wilson may be deemed to share the voting and dispositive control over the shares of common stock owned by Petrohawk. FCW, LLC, a member of Petrohawk, has the contractual right to nominate one of the members of the board of managers of Petrohawk pursuant to Petrohawk s governing documents and has nominated Floyd C. Wilson, a majority member of FCW, LLC. Floyd C. Wilson disclaims beneficial ownership of the reported securities in excess of his pecuniary interest in the securities.

(16) Includes 15,000 shares expected to be granted after the closing to each of the non-employee directors who will then be serving on our board for his service on the board of directors.

(17) Total for nine persons who will be officers or directors after the issuance of the securities to Petrohawk will be 25,391,515 shares (representing 67.15% of the shares then outstanding) after the closing of the Petrohawk transaction and the termination or resignation of all of the current directors and officers other than Mr. Stone. This will include 15,216,515 shares of common stock, 10,000,000 shares of common stock underlying stock purchase warrants and options to purchase 175,000 shares underlying stock options.

Equity Compensation Plan Information

The following table sets forth certain information as of December 31, 2003 with respect to compensation plans (including individual compensation arrangements) under which equity securities of the Company are authorized for issuance.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	889,083	$ 3.18	545,917
Equity compensation plans not approved by security holders			
Total	889,083	$ 3.18	545,917

Item 13. Certain Relationships And Related Transactions

Director Robert E. Davis, Jr. has overriding royalty interests in certain of our oil and gas properties that were acquired from Red River Energy, LLC in September 2000. Mr. Davis, former Executive Vice President and Chief Financial Officer of Red River, received the overriding royalty interests as part of his compensation while employed at Red River. Mr. Davis received approximately $49,800 in royalty income from Beta properties during 2003.

Director Rolf N. Hufnagel, director since June 20, 2003, and his wife have overriding royalty interests in certain of our oil and gas properties that were acquired from Red River in September 2000. Mr. Hufnagel received the overriding royalty interests as part of his compensation while employed at Red River. Mr. Hufnagel and his wife together received a total of approximately $136,300 in royalty income from Beta properties during 2003.

Item 14. Principal Accountant Fees and Services

Audit Fees

Our principal accounting firm for the 2003 fiscal year, effective June 20, 2003, was Ernst & Young LLP (Ernst & Young) and for the fiscal year 2002, including and up to June 20, 2003 was HEIN & ASSOCIATES LLP (HEIN). The aggregate fees billed by Ernst & Young for professional services rendered for the audit of our annual financial statements, reviews of the financial statements included in our Quarterly Reports on Form 10-Q, consultations, and other consents to or assistance with Securities and Exchange Commission filings for the year ended December 31, 2003 was $107,000. The aggregate fees billed by HEIN for professional services rendered for the audit of our annual financial statements, reviews of the financial statements included in our Quarterly Reports on Form 10-Q, consultations, and other consents to or assistance with Securities and Exchange Commission filings for the years ended December 31, 2003 (through June 20, 2003) and December 31, 2002 was $18,170 and $107,609, respectively.

Audit Related Fees

The Company did not engage Ernst & Young or Hein for any professional services that would be considered audit related fees during the years ended December 31, 2003 and 2002.

Tax Fees

The aggregate fees billed by HEIN for professional services relating to tax compliance, tax advice and preparation of our federal and state income tax returns and state franchise tax returns for the years ended December 31, 2003 and 2002 were $13,203 and $26,708, respectively.

All Other Fees

We did not engage Ernst & Young or HEIN for any additional professional services other than as disclosed above for the years ended December 31, 2003 and 2002.

Audit Committee Pre-Approval Policy

All audit fees, audit related fees and tax fees as described above for the year ended December 31, 2003 were pre-approved by our Audit Committee, which concluded that the provision of such services by Ernst & Young and HEIN was compatible with the maintenance of Ernst & Young s and HEIN s independence in the conduct of their auditing functions. Our Audit Committee s Pre-Approval Policy provides that pre-approval of all such services must be approved separately by the Audit Committee. The Audit Committee has not delegated any such pre-approval authority.

PART IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) (1) Financial Statements:

The financial statements of the Company and its subsidiaries and report of independent public accountants listed in the accompanying Index to Financial Statements are filed as a part of this Form 10-K

(2) Financial Statements Schedules:

All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:

The following documents are included as exhibits to this Form 10-K.

EXHIBIT NUMBER	DESCRIPTION
3.1	Original Articles of Incorporation of Registrant as amended on March 19, 1998, incorporated by reference to Exhibit 3.1 of Beta s S-1 Registration Statement No. 333-68381 filed December 4, 1998.
3.2	Certificate of Amendment of Articles of Incorporation of the Registrant, dated August 28, 2000, incorporated by reference to Exhibit 3.1 of Beta s Annual Report of Form 10-K filed for the year ended December 31, 2000.
3.3	Amended and Restated Bylaws of the Registrant, dated June 20, 2003, incorporated by reference to Exhibit 3.01 of Beta s Second Quarter 2003 Form 10-Q filed August 13,2003.
4.1	Form of Warrant Agreement covering warrants issued to employees as employment inducements.*
4.2	Warrant Agreement between Beta and Brookstreet Securities dated July 30, 1999.*
4.3	Form of Warrant Agreement with suppliers, service providers and other third parties.*
4.4	Certificate of Designation of Beta Oil & Gas, Inc.'s 8% Cumulative Convertible Preferred Stock, incorporated by reference to Exhibit 3.1 of Beta's Form 8-K filed on July 3, 2001.
4.5	Warrant Agreement between Beta and its preferred shareholders, including Warrant Certificates A and B, incorporated by reference to Exhibit 4.1 of Beta's Form 8-K filed on July 3, 2001.
10.1	Formosa Grande Prospect Agreement, Dated August 1, 1997, incorporated by reference to Exhibit 10.1 of Beta s S-1 Registration Statement No. 333-68381 filed December 4, 1998.
10.2	Texana Prospect Agreement, Dated July 15, 1997, incorporated by reference to Exhibit 10.2 of Beta s S-1 Registration Statement No. 333-68381 filed December 4, 1998.
10.3	Ganado Prospect Agreement, Dated November 1, 1997, incorporated by reference to Exhibit 10.3 of Beta s S-1 Registration Statement No. 333-68381 filed December 4, 1998..
10.4	

	Lapeyrouse Prospect Agreement, Dated October 13, 1997, incorporated by reference to Exhibit 10.5 of Beta s S-1 Registration Statement No. 333-68381 filed December 4, 1998.
10.5	Rozel (Transition Zone) Prospect Agreement, Dated February 24,1998, incorporated by reference to Exhibit 10.6 of Beta s S-1 Registration Statement No. 333-68381 filed December 4, 1998.
10.6	Steve Antry Employment Agreement, Dated June 23,1997 incorporated by reference to Exhibit 10.9 of Beta s S-1 Registration Statement No. 333-68381 filed December 4, 1998.
10.7	BWC Prospect Agreement, Dated April 1, 1998, incorporated by reference to Exhibit 10.14 of Beta s S-1 Registration Statement No. 333-68381 filed December 4, 1998.
10.8	Redfish Prospect Agreement Dated January 6, 1999, incorporated by reference to Exhibit 10.19 of Beta s Amendment No. 2 to S-1/A Registration Statement No. 333-68381 filed May 3, 1999.
10.9	Shark Prospect Agreement Dated January 6, 1999, incorporated by reference to Exhibit 10.20 of Beta s Amendment No. 2 to S-1/A Registration Statement No. 333-68381 filed May 3, 1999.
10.10	Northeast Hitchcock Agreement Dated July 30, 1999, incorporated by reference to Exhibit 10.24 of Beta s Form 10-K/A for the year 1999 filed March 30, 2000.
10.11	Sarah White Agreement Dated July 30, 1999, incorporated by reference to Exhibit 10.25 of Beta s Form 10-K/A for the year 1999 filed March 30, 2000.
10.12	Revised Joint Development Agreement dated August 8, 2000 between Red River Energy, L.L.C. and Avalon Exploration, Inc., incorporated by reference to Exhibit 10.27 of Beta s Third Quarter Form 10-Q filed November 14, 2000.
10.13	Mushroom Project Participation Agreement, Austin and Waller Counties, Texas, dated June 14, 2000, incorporated by reference to Exhibit 10.29 of Beta s Form 10-K for the year 2000 filed April 2, 2001.

10.14	Starboard Area Letter Agreement, Terrebone Parish, Louisiana dated June 16, 2000 incorporated by reference to Exhibit 10.30 of Beta s Form 10-K for the year 2000 filed April 2, 2001.
10.15	First Amended and Restated Revolving Credit Agreement between Bank of Oklahoma and Red River Energy, LLC dated March 30, 1999, incorporated by reference to Exhibit 10.31 of Beta s Form 10-K for the year 2000 filed April 2, 2001.
10.16	First Amendment to First Amended and Restated Revolving Credit Agreement between Bank of Oklahoma and Red River Energy, LLC dated February 1, 2000, incorporated by reference to Exhibit 10.32 of Beta s Form 10-K for the year 2000 filed April 2, 2001.
10.17	Second Amendment to First Amended and Restated Revolving Credit Agreement between Bank of Oklahoma and Red River Energy, LLC dated June 15, 2000, incorporated by reference to Exhibit 10.33 of Beta s Form 10-K for the year 2000 filed April 2, 2001.
10.18	Third Amendment to First Amended and Restated Revolving Credit Agreement between Bank of Oklahoma and Beta Oil & Gas, Inc. dated March 19, 2001, incorporated by reference to Exhibit 10.34 of Beta s Form 10-K for the year 2000 filed April 2, 2001.
10.19	Form of Placement Agent Agreement for Preferred Placement Offering dated March 15, 2001, incorporated by reference to Exhibit 10.35 of Beta s Form 10-K for the year 2000 filed April 2, 2001.
10.20	Letter Agreement Between Avalon Exploration, Inc. and Beta Oil & Gas, Inc. dated September 7, 2001 amending Revised Joint Development Agreement dated August 8, 2000 between Red River Energy, L.L.C. and Avalon Exploration, Inc., incorporated by reference to Exhibit 10.27 of Beta s Third Quarter Form 10-Q filed November 14, 2000.
10.21	The Amended 1999 Incentive and Nonstatutory Stock Option Plan, incorporated by reference to Exhibit 99 of Beta s 14A Definitive Proxy Statement dated and filed August 14, 2000.
10.22	Fourth Amendment to First Amended and Restated Revolving Credit Agreement dated March 15, 2002 between Beta Oil & Gas, Inc. and Bank of Oklahoma, N.A., incorporated by reference to Exhibit 10.36 of Beta s Second Quarter 2002 Form 10-Q filed August 14, 2002.
10.23	Promissory Note dated March 15, 2002 between Beta Oil & Gas, Inc. and Bank of Oklahoma, N.A., incorporated by reference to Exhibit 10.37 of Beta s Second Quarter 2002 Form 10-Q filed August 14, 2002.
10.24	Revolving Credit Note dated March 15, 2002 between Beta Oil & Gas, Inc. and Bank of Oklahoma N.A., incorporated by reference to Exhibit 10.38 of Beta s Second Quarter 2002 Form 10-Q filed August 14, 2002.
10.25	Agreement between Beta Oil & Gas, Inc., Penn Virginia Oil & Gas Corporation, et.al. dated September 3, 2002, incorporated by reference to Exhibit 10.38 of Beta s Third Quarter 2002 Form 10-Q filed November 14, 2002.
10.26	Letter Agreement between Beta Oil & Gas, Inc. and David A. Wilkins dated September 16, 2002 regarding the terms of his employment.*
10.27	Separation Agreement with between Steve Antry and Beta Oil & Gas, Inc.dated October 1, 2002.*
10.28	Employment Inducement Stock Option Agreement between Beta Oil & Gas, Inc. and David A. Wilkins dated October 1, 2002.*
10.29	Fifth Amendment to First Amended and Restated Revolving Credit Agreement dated June 30, 2003 between Beta Oil & Gas, Inc. and Bank of Oklahoma, N.A., incorporated by reference to Exhibit 10.42 of Beta s Second Quarter 2003 Form 10-Q filed August 13, 2003.
10.30	Promissory Note dated June 30, 2003 between Beta Oil & Gas, Inc. and Bank of Oklahoma, N.A., incorporated by reference to Exhibit 10.43 of Beta s Second Quarter 2003 Form 10-Q filed August 13,2003.
10.31	Second Amendment to Second Amended and Supplemental Mortgage, Deed of Trust, Security Agreement, Financing Statement and Assignment dated June 30, 2003 from Beta Operating Company, L.L.C. to Michael M. Coats, Trustee and Bank of Oklahoma, N.A., incorporated by reference to Exhibit 10.44 of Beta s Second Quarter 2003 Form 10-Q filed August 13,2003.
10.32	Amendment One to Amended and Restated 1999 Incentive and Nonstatutory Stock Option Plan, incorporated by reference to Exhibit 10.45 of Beta s Second Quarter 2003 Form 10-Q filed August 13,2003.
10.33	Agreement among Beta Oil & Gas, Inc., Steve A. Antry, Rolf N. Hufnagel, Robert E. Davis, Jr., Robert C. Stone, Jr. and David A. Wilkins, dated June 20, 2003, regarding voting of shares at 2003 annual meeting incorporated by reference to Exhibit 10.1 of Beta's Form 8-K filed on June 24, 2004.
10.34	Operating Agreement dated July 31, 2003 and effective July 1, 2003, between Beta Operating Company, L.L.C. and Woolsey Petroleum relating to a 13 well drilling commitment, incorporated by reference to Exhibit 10.46 of Beta s Third Quarter 2003 Form 10-Q filed November 14,2003.
10.35	Letter agreement dated July 9, 2003, between Beta Oil & Gas, Inc. and Petro Capital Advisors, L.L.C. relating to financial advisory services, incorporated by reference to Exhibit 10.47 of Beta s Third Quarter 2003 Form 10-Q filed November 14, 2003.
10.36	Letter agreement dated October 13, 2003 between Beta Oil & Gas, Inc. and Petro Capital Advisors, LLC

	amending certain terms under the July 9, 2003 letter agreement, incorporated by reference to Exhibit 10.48 of Beta s Third Quarter 2003 Form 10-Q filed November 14, 2003.
10.37	Securities Purchase Agreement dated December 12, 2003 between Beta Oil & Gas, Inc. and Petrohawk Energy, LLC, incorporated by reference to Appendix A to Beta's Preliminary Proxy Statement filed on Schedule 14A on January 9, 2004.
10.38	Stockholders Agreement by and among Beta Oil & Gas, Inc. and certain of its stockholders, incorporated by reference to Appendix E to Beta's Preliminary Proxy Statement on Schedule 14A on January 9, 2004.
14.1	Code of Ethics
16.1	Letter of HEIN & Associates LLP is incorporated by reference to Exhibit 16 Beta s Current Report on Form 8-K/A filed on May 19, 2003.
21.1	List of Subsidiaries incorporated by reference to Exhibit 21 of Beta s Form 10-K for the year 2000 filed April 2, 2001.
23.1	Consent of Hein & Associates, LLP. dated April 16, 2004
23.2	Consent of Ryder Scott Company, L.P. dated April 16, 2004
23.3	Consent of Ernst & Young LLP dated April 16, 2004
23.4	Consent of Netherland, Sewell & Associates, Inc.dated April 15, 2004
31.1	Certificate of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certificate of Chief Financial Officer under Section 302 of Sarbanes-Oxley Act of 2002
32.1	Certificate of Chief Executive Officer and Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002

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* Previously filed with this Form 10-K.

(b) Beta did not file any current reports on Form 8-K during the fourth quarter of 2003.

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BETA OIL & GAS, INC.

Date: April 19, 2004

By: /s/ David A. Wilkins

David A. Wilkins
Chief Executive Officer and President

By: /s/ Joseph L. Burnett

Joseph L. Burnett
Chief Financial Officer, and
Principal Accounting Officer

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors and Stockholders

of Beta Oil & Gas, Inc.

We have audited the accompanying consolidated balance sheet of Beta Oil & Gas, Inc. as of December 31, 2003, and the related consolidated statements of operations, changes in stockholders equity and cash flows for the year then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Beta Oil & Gas, Inc. at December 31, 2003, and the consolidated results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States.

As discussed in Notes 1 and 5 to the consolidated financial statements, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, *Asset Retirement Obligations*. In addition, as also discussed in Note 1, effective January 1, 2003, the Company adopted, prospectively, the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation.*

ERNST & YOUNG LLP

Tulsa, Oklahoma
March 19, 2004

INDEPENDENT AUDITOR S REPORT

The Stockholders and Board of Directors

Beta Oil & Gas, Inc.

Tulsa, Oklahoma

We have audited the consolidated balance sheets of Beta Oil & Gas, Inc. and subsidiaries as of December 31, 2002, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the years in the two-year period ended December 31, 2002. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Beta Oil & Gas, Inc. and subsidiaries as of December 31, 2002 and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

/s/HEIN & ASSOCIATES LLP

HEIN & ASSOCIATES LLP
Certified Public Accountants

Orange, California
February 14, 2003

BETA OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	DECEMBER 31,	
	2003	**2002**
CURRENT ASSETS:		
Cash	$ 2,109,681	$ 927,313
Accounts receivable		
Oil and gas sales	1,898,746	1,676,935
Other	113,529	149,243
Income tax receivable	5,934	52,115
Prepaid expenses and other	266,728	187,818
Total current assets	4,394,618	2,993,424
OIL AND GAS PROPERTIES, at cost (full cost method)		
Evaluated properties	78,717,380	70,907,441
Unevaluated properties	1,294,212	4,582,605
Less accumulated amortization and impairment of full cost pool	(39,740,116)	(35,133,445)
Net oil and gas properties	40,271,476	40,356,601
OTHER OPERATING PROPERTY AND EQUIPMENT, at cost		
Gas gathering system	1,496,404	1,507,177
Support equipment	197,379	221,413
Other	276,498	215,302
Less accumulated depreciation	(813,450)	(616,865)
Net other operating property and equipment	1,156,831	1,327,027
OTHER ASSETS	292,318	76,208
TOTAL ASSETS	$ 46,115,243	$ 44,753,260
CURRENT LIABILITIES:		
Notes payable	$ 67,570	$ 70,831
Accounts payable, trade	1,578,989	1,909,226
Futures transaction hedge liability		702,417
Dividends payable	112,707	112,707
Asset retirement obligation current portion	171,860	
Other accrued liabilities	566,990	275,290
Total current liabilities	2,498,116	3,070,471
LONG-TERM DEBT, less current portion	13,284,652	13,634,652
ASSET RETIREMENT OBLIGATION	1,062,860	

COMMITMENTS AND CONTINGENCIES (Note 6)				
STOCKHOLDERS EQUITY				
Preferred stock, $.001 par value, 5,000,000 shares authorized; 604,271 shares issued and outstanding at December 31, 2003 and 2002; liquidation value at December 31, 2003 and 2002 is $5,702,097.		604		604
Common stock, $.001 par value; 50,000,000 shares authorized; 12,446,072 shares issued; 12,429,307 and 12,440,057 shares outstanding at December 31, 2003 and 2002, respectively		12,447		12,447
Additional paid-in capital		51,924,225		51,917,235
Treasury stock, at cost; 16,765 and 6,015 shares reacquired at December 31, 2003 and December 31, 2002, respectively		(36,428)		(28,153)
Accumulated other comprehensive income				(702,417)
Accumulated deficit		(22,631,233)		(23,151,579)
Total stockholders equity		29,269,615		28,048,137
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	46,115,243	$	44,753,260

See accompanying notes to consolidated financial statements.

BETA OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	FOR THE YEARS ENDED DECEMBER 31,		
	2003	**2002**	**2001**
REVENUES:			
Oil and gas sales	$ 12,276,495	$ 9,244,530	$ 12,788,115
Field services	648,194	403,311	868,406
Total revenue	12,924,689	9,647,841	13,656,521
COSTS AND EXPENSES:			
Lease operating expense	3,173,985	3,304,921	3,469,194
Field services	185,254	195,430	339,329
General and administrative	3,082,605	2,209,887	2,679,121
Full cost ceiling impairment	129,279	5,163,689	13,805,035
Depreciation and amortization expense	4,857,597	5,120,572	5,176,897
Total costs and expenses	11,428,720	15,994,499	25,469,576
INCOME (LOSS) FROM OPERATIONS	1,495,969	(6,346,658)	(11,813,055)
OTHER INCOME (EXPENSE):			
Interest expense	(476,078)	(558,297)	(867,835)
Interest income and other	(30,034)	23,343	130,374
Total other expense	(506,112)	(534,954)	(737,461)
INCOME (LOSS) BEFORE TAX PROVISION	989,857	(6,881,612)	(12,550,516)
INCOME TAX BENEFIT (PROVISION)	(24,000)		3,504,432
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE	965,857	(6,881,612)	(9,046,084)
CUMULATIVE EFFECT ON PRIOR YEARS FROM ADOPTION OF FASB STATEMENT NO. 143, ACCOUNTING FOR ASSET RETIREMENT OBLIGATION	1,640		
NET INCOME (LOSS)	967,497	(6,881,612)	(9,046,084)
PREFERRED DIVIDENDS	(447,151)	(447,151)	(231,821)
NET INCOME (LOSS) APPLICABLE TO COMMON SHAREHOLDER	$ 520,346	$ (7,328,763)	$ (9,277,905)
BASIC NET INCOME (LOSS) PER COMMON SHARE	$ .04	$ (.59)	$ (.75)
DILUTED NET INCOME (LOSS) PER COMMON SHARE	$ .04	$ (.59)	$ (.75)
COMPREHENSIVE INCOME (LOSS):			
NET INCOME (LOSS)	$ 967,497	$ (6,881,612)	$ (9,046,084)

OTHER COMPREHENSIVE INCOME:						
Transition adjustment related to change in accounting for derivative instruments and hedging activities (net of income taxes)						(953,488)
Reclassification of realized loss on qualifying cash flow hedges (net of income taxes)		1,336,844		829,248		340,048
Unrealized gain (loss) on qualifying cash flow hedges (net of income taxes)		(634,427)		(1,600,173)		681,948
TOTAL COMPREHENSIVE INCOME (LOSS)	$	1,669,914	$	(7,652,537)	$	(8,977,576)

See accompanying notes to consolidated financial statements.

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BETA OIL & GAS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

	PREFERRED		COMMON		ADDITIONAL PAID IN CAPITAL	TREASURY STOCK	ACCUMULATED COMPREHENSIVE INCOME	ACCUMULATED DEFICIT	TOTAL STOCKHOLDERS EQUITY
	SHARES	AMOUNT	SHARES	AMOUNT					
BALANCES, January 1, 2001		$	12,340,951	$ 12,341	$ 46,592,976	$	$	$ (6,544,911)	$ 40,060,406
Issuance of shares pursuant to private placement, net	604,271	604			5,040,924				5,041,528
Issuance of shares for warrant exercise			57,621	58	180,799				180,857
Treasury stock acquired						(198,920)			(198,920)
Preferred dividends								(231,821)	(231,821)
Transition adjustment related to change in accounting for derivative instruments and hedging activities (net of income taxes)							(953,488)		(953,488)
Reclassification of realized (gain) loss on qualifying cash flow hedges (net of income taxes)							340,048		340,048
Unrealized gain (loss) on qualifying cash flow hedges (net of income taxes)							681,948		681,948
Net loss								(9,046,084)	(9,046,084)
BALANCES, Dec. 31, 2001	604,271	604	12,398,572	12,399	51,814,699	(198,920)	68,508	(15,822,816)	35,874,474
			47,500	48	94,952				95,000

Issuance of shares for warrant exercise									
Compensation associated with warrant extension					14,842				14,842
Treasury stock issued						170,767			170,767
Offering costs pursuant to 2001 private placement					(7,258)				(7,258)
Preferred dividends								(447,151)	(447,151)
Reclassification of realized (gain) loss on qualifying cash flow hedges							829,248		829,248
Unrealized gain (loss) on qualifying cash flow hedges							(1,600,173)		(1,600,173)
Net loss								(6,881,612)	(6,881,612)
BALANCES, December 31, 2002	604,271	$ 604	12,446,072	$ 12,447	$ 51,917,235	(28,153)	$ (702,417)	$ (23,151,579)	$ 28,048,137
Compensation associated with issuance of options					251,972				251,972
Treasury stock acquired						(8,275)			(8,275)
Deferred offering costs relative to Petrohawk transaction					(244,982)				(244,982)
Preferred dividends								(447,151)	(447,151)
Reclassification of realized (gain) loss on qualifying cash flow hedges							1,336,844		1,336,844
Unrealized gain (loss) on qualifying cash flow hedges							(634,427)		(634,427)
Net income								967,497	967,497
BALANCES, December 31, 2003	604,271	$ 604	12,446,072	$ 12,447	$ 51,924,225	$ (36,428)	$	$ (22,631,233)	$ 29,269,615

See accompanying notes to consolidated financial statements

BETA OIL & GAS INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	FOR THE YEARS ENDED DECEMBER 31,		
	2003	**2002**	**2001**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss) before cumulative effect of change in accounting principle	$ 965,857	$ (6,881,612)	$ (9,046,084)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	4,857,597	5,120,572	5,176,897
Loss on sale of equipment	35,684		6,865
Impairment expense	129,279	5,163,689	13,805,035
Deferred income tax			(3,526,304)
Compensation expense from stock option issuances	251,972		
Compensation associated with warrant extension		14,842	
Change in operating assets and liabilities:			
Accounts receivable	(186,097)	325,744	709,922
Income tax receivable	46,181	(13,612)	(38,503)
Prepaid expenses	(78,910)	(323)	13,120
Accounts payable, trade	(330,237)	(562,979)	1,828,791
Income taxes payable			(198,650)
Accretion of asset retirement obligation	50,245		
Asset retirement obligation incurred	(34,965)		
Other accrued expenses	291,700	(188,569)	316,006
Net cash provided by operating activities	5,998,306	2,977,752	9,047,095
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas property expenditures	(4,043,424)	(6,838,779)	(14,927,031)
Proceeds received from sale of oil and gas properties	549,287	3,229,388	1,065,989
Gas gathering and equipment expenditures	(52,022)	(36,103)	(177,103)
Proceeds received from equipment sale		2,556	16,535
Change in other assets	(216,110)	1,396,361	(726,430)
Net cash used in investing activities	(3,762,269)	(2,246,577)	(14,748,040)

	FOR THE YEARS ENDED DECEMBER 31,		
	2003	**2002**	**2001**
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from exercise of warrants and options		95,000	180,857
Proceeds from premiums payable	284,852	233,637	152,680
Repayment of premiums payable	(274,038)	(221,401)	(174,284)
Proceeds from notes payable			900,000
Repayment of notes payable	(364,075)	(12,887)	(1,061,789)
Proceeds from preferred stock private placement			5,589,390
Offering costs for preferred stock private placement		(7,258)	(547,862)
Deferred offering costs relative to pending Petrohawk transaction	(244,982)		
Acquisition of treasury stock	(8,275)		(198,920)
Dividends paid	(447,151)	(447,152)	(119,114)
Net cash provided by (used in) financing activities	(1,053,669)	(360,061)	4,720,958
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,182,368	371,114	(979,987)
CASH AND CASH EQUIVALENTS			
Beginning of period	927,313	556,199	1,536,186
End of period	$ 2,109,681	$ 927,313	$ 556,199
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash paid for:			
Interest	$ 518,800	$ 515,524	$ 867,835
Income taxes	$ 32,500	$ 13,612	$ 236,000
SUPPLEMENTAL DISCLOSURE OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Fair value of common stock and warrants issued for:			
Oil and gas properties	$	$ 170,267	$

See accompanying notes to consolidated financial statements.

BETA OIL & GAS INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. **BUSINESS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**:

Consolidation - Beta Oil and Gas, Inc. is engaged in the business of acquiring, exploring and developing oil and gas properties. All of the Company s operating income is derived from core areas located in Texas, Oklahoma, Kansas and Louisiana. The accompanying consolidated financial statements include the accounts of Beta Oil & Gas, Inc. and its wholly owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates - The preparation of the Company s consolidated financial statements in conformity with generally accepted accounting principles requires the Company s management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The estimates include oil and gas reserve quantities which form the basis for the calculation of amortization and impairment of oil and gas properties. Management emphasizes that reserve estimates are inherently imprecise and that estimates of more recent discoveries are more imprecise than those for properties with long production histories. Actual results could materially differ from these estimates.

Oil and Gas Properties - The Company accounts for its oil and gas producing activities using the full cost method of accounting as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general corporate costs are expensed as incurred. In general, sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded. Amortization of evaluated oil and gas properties is computed on the units of production method based on all proved reserves on a country-by-country basis. Unevaluated oil and gas properties are assessed at least annually for impairment either individually or on an aggregate basis, if the properties have similar characteristics. The net capitalized costs of evaluated oil and gas properties are subject to a full cost ceiling limitation- in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations. Any impairments to unevaluated properties are recorded as transfers to the full cost pool.

Joint Ventures - All exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect only the Company s proportionate interest in such activities.

Revenue Recognition - The Company recognizes oil and gas sales upon delivery to the purchaser. Under the sales method, the Company and other joint owners may sell more or less than their entitled share of the natural gas volume produced. Should the Company s excess sales of natural gas exceed its share of estimated remaining recoverable reserves a liability is recorded and revenue is deferred.

Other Operating Property and Equipment - Other operating property and equipment are stated at cost. Provision for depreciation and amortization on property and equipment is calculated using the straight-line and accelerated methods over the estimated useful lives (ranging from 3 to 10 years) of the respective assets. Amortization from the gathering assets is computed on a units of revenue method based on the total future gross revenues. The cost of normal maintenance and repairs is charged to operating expense as incurred. Material expenditures, which increase the life of an asset, are capitalized and depreciated over the estimated remaining useful life of the asset. The cost of properties sold, or otherwise disposed of, and the related accumulated depreciation or amortization are removed from the accounts, and any gain or losses are reflected in current operations.

Asset Retirement Obligation - In August 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143). The Company was required to adopt this new standard beginning January 1, 2003. SFAS No. 143 requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Upon adoption, the Company recorded an asset retirement obligation to reflect the Company s legal obligations related to future plugging and abandonment of its oil and gas wells. The Company estimated the expected cash flow associated with the obligation and discounted the amount using a credit-adjusted, risk-free interest rate. The transition adjustment resulting from the adoption of SFAS No. 143 was reported as a cumulative effect of a change in accounting principle. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggests the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment.

Impairment of Long-Lived Assets - In the event that facts and circumstances indicate that the costs of long-lived assets, other than oil and gas properties, may be impaired, an evaluation of recoverability would be performed. If an evaluation is required, the estimated future undiscounted cash flows associated with the asset would be compared to the asset s carrying amount to determine if a write-down to market value or discounted cash flow value is required. Impairment of oil and gas properties is evaluated subject to the full cost ceiling as described under *Oil and Gas Properties*.

Income Taxes - The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Concentrations of Credit Risk - Credit risk represents the accounting loss that would be recognized at the reporting date if counter parties failed completely to perform as contracted. Concentrations of credit risk (whether on or off balance sheet) that arise from financial instruments exist for groups of customers or counter parties when they have similar economic characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions described below.

The Company operates in one segment, the oil and gas industry. A geographic concentration exists because the Company s customers are generally located within the Central United States. Financial instruments that subject the Company to credit risk consist principally of oil and gas sales which are based solely on short-term purchase contracts from various customers with related accounts receivable subject to credit risk.

The table below shows the purchasers that each accounted for 10% or more of the Company s revenue during the specified years.

	2003	2002
Duke Energy Field Services, LLC	33%	31%
Allegro Investments	10%	14%
Sunoco, Inc.	10%	9%

We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and gas we produce. Other purchasers are available in our areas of operations.

Fair Value of Financial Instruments - The estimated fair values for financial instruments under FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of long-term debt approximates its carrying value because the debt carries interest rates that approximate current market rates.

Stock Based Compensation - On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* (SFAS No. 123) and related interpretations in accounting for its employee and director stock options and applies the fair value based method of accounting to such options. Under SFAS No. 123, the fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model. Under Statement of Financial Accounting Standards No. 148 *Accounting for Stock-Based Compensation Transition and Disclosure*, an amendment to SFAS No. 123, certain transitional alternative wereavailable for a voluntary change to the fair value based method of accounting for stock-based employee compensation if adopted in a fiscal year beginning before December 16, 2003. The Company used the *prospective method* which applies prospectively the fair value recognition method to all employee and director awards granted, modified or settled after the beginning of the fiscal year in which the fair value based method of accounting for stock-based compensation is adopted. Previous to the adoption, the Company elected to follow Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and related interpretations in accounting for its employee stock options. However, as required by SFAS No. 123, the Company disclosed on a pro forma basis the impact of the fair value accounting for employee stock options. Transactions in equity instruments with non-employees for goods or services have been accounted for using the fair value method as prescribed by SFAS No. 123.

Since the Company adopted the fair value recognition provisions of SFAS No. 123 prospectively for all employee awards granted, modified or settled after January 1, 2003, the cost related to stock-based compensation included in the determination of income for the twelve month period ended December 31, 2003, 2002 and 2001 is less than that which would have been recognized if the fair value method had been applied to all awards since the original effective date of SFAS No. 123. Awards vest over periods ranging from one to three years. The following table illustrates the effect on net income (loss) and earnings (loss) per share as if the fair value based method had been applied to all outstanding and unvested awards in each period.

	FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003	2002	2001
Net income (loss) applicable to common shareholders as reported	$ 520,346	$ (7,328,763)	$ (9,277,905)
Add: Stock-based compensation expense included in reported net income (loss)	251,972		
	(406,431)	(240,534)	(237,164)

Deduct: Total stock-based compensation expense determined under fair value method for all awards						
Pro forma net income (loss) applicable to common shareholders	$	365,887	$	(7,569,297)	$	(9,515,069)
Income (loss) per share;						
Basic as reported	$	.04	$	(.59)	$	(.75)
Basic pro forma	$	.03	$	(.61)	$	(.77)
Diluted as reported	$	.04	$	(.59)	$	(.75)
Diluted pro forma	$	.03	$	(.61)	$	(.77)

The fair value of each grant is estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average assumptions used for options granted in 2003 include expected volatility of approximately 61.3%, a risk-free interest rate of 3.15% and expected lives of 5.2 years. The weighted average assumptions used for options granted in 2002 include expected volatility of approximately 56.1%, a risk-free interest rate of 2.71% and expected lives of 3.7 years. The weighted average assumptions used for options granted in 2001 include expected volatility of approximately 53.1%, a risk-free interest rate of 3.73% and expected lives of 2 years.

Derivative and Hedging Activities - In June 1998, the FASB issued Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No.133).The FASB subsequently issued Statements No. 137 and Statement No. 138 which are amendments to SFAS No. 133. The Company adopted SFAS No. 133, as amended, beginning January 1, 2001.

SFAS No. 133 establishes accounting and reporting standards for derivative instruments and for hedging activities. All derivatives are recorded in current earnings unless specific hedge accounting criteria are met, including formally designating and assessing the effectiveness of the transactions that receive hedge accounting treatment. From time to time, the Company may hedge a portion of its natural gas and/or crude oil production. Derivative contracts entered into by the Company have consisted of cash flow hedge transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. Changes in the fair value of these derivative instruments are recorded in other comprehensive income and are reclassified as earnings in the periods in which earnings are impacted by the variability of the cash flows of the hedged item. The ineffective portion related to basis changes and time value of all hedges is recognized in current period earnings.

Earnings Per Share - Basic EPS is calculated by dividing the income or loss available to common shareholders by the weighted average number of shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

Statement of Cash Flows - For purposes of the statement of cash flows, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

New Accounting Pronouncements - In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51* and revised this interpretation in December 2003 (FIN 46). FIN 46 requires the consolidation of variable interest entities by their primary beneficiary if the variable interest entities do not effectively disperse risks among the parties involved. Previously, entities were generally consolidated by an enterprise when it had a controlling financial interest through ownership of a majority of voting interest in the entity. The adoption of FIN 46 had no impact on the company s financial position or results of operations.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (SFAS 149). SFAS 149 is intended to result in more consistent reporting of contracts as either freestanding derivative instruments subject to SFAS 133 in its entirety, or as hybrid instruments with debt host contracts and embedded derivative features. SFAS 149 was effective for contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003. The adoption of SFAS 149 had no impact on the company s financial position or results of operations.

On May 15, 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* (SFAS 150). SFAS 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. SFAS 150 must be applied immediately to instruments entered into or modified after May 31, 2003, and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. Early adoption of SFAS 150 is not permitted. The adoption of SFAS 150 had no impact on the company s financial position or results of operations.

2. ACQUISITIONS, SALES AND OIL AND GAS OPERATIONS:

Acquisitions and Sales - In 2003, the Company acquired additional working interests in certain non-operated properties, in which it had existing working interests, for $480,000. Subsequent to the purchase of the 20% working interests, the acquired working interests were sold for $530,000.

In 2002, the Company sold interests in various internally generated prospects, unevaluated acreage and minority interests in non-core marginal producing properties for $3,229,388 and certain drilling promotes. The prospects were ready for sale as the Company had completed the leasing activity in late 2001. The following discussion addresses the activity that occurred in 2002, with updated information from 2003 activity or events.

1.) Lake Boeuf prospect, Lafourche Parish, Louisiana 87.5% of the Company s 100% interest was sold with the Company retaining a 12.5% working interest after casing point. The Company received cash and a drilling promote on the interest sold. This acreage is 100% unevaluated and has no proved reserves. Subsequent to December 31, 2002, the party which purchased 75% of the 87.5% working interest indicated they would not be able to fulfill their obligation to drill the prospect. The Company retained the proceeds received from the party. In 2003, the Company was unsuccessful in its pursuit of other parties to purchase the remaining interest in the prospect. The acreage was allowed to expire and the associated net costs were transferred to U.S. evaluated properties.

2.) North Mexican Sweetheart prospect, Jackson County, Texas - Approximately 90% of the Company s working interest in the acreage was sold in this deep Yegua prospect for approximately $145,000. The Company retained a 12.5% working interest after payout of the initial test well. At the time of sale, this acreage was 100% unevaluated and had no proved reserves. As a result of unsuccessful drilling activity surrounding the prospect in 2003, the associated net costs for the prospect were transferred to U.S. evaluated costs in 2003.

3.) West Broussard prospect and surrounding acreage - The Company entered into an agreement with an industry partner in September 2002, whereby the partner had an option, but not an obligation, to drill one well in both the East and West units of the prospect, with the East unit well being the initial well. Upon execution of the agreement, the Company received $650,000 for consideration of certain rights and information granted to the partner. This payment represented a partial reimbursement of the Company s cost in the prospect. Under the terms of the agreement, the partner was required to make a second payment to the Company of $650,000 upon the partner s election to drill the well in the East unit, which was made in November 2002. The well in the East unit commenced drilling in the first quarter of 2003 and commenced sales at the end of September 2003. The Company has an approximate 4.8% working interest in the East unit well before payout, increasing to a 10.1% working interest after payout. The partner had an option to drill a well in the West unit at which time the Company would receive an additional $1,300,000. In October 2003, the partner notified the Company it elected not to exercise its option to drill a well in the West unit. At that time, the Company had a working interest ownership in the West unit of approximately 83.6%. Subsequent to December 31, 2003, the Company entered into an arrangement with three parties, whereby upon closing of the arrangement the Company will receive approximately $731,500 for approximately 74% of the Company s working interest in the prospect. Additionally, the Company will receive approximately $1.1 million in production payments from future net cash flow from the well, if successful, and will receive an additional 4.2% working interest after well payout. Upon closing of the arrangement the Company will have a 9.6% working interest in the well increasing to a 13.8 % working interest after well payout. Petrohawk is participating in this prospect with a 15% working interest. For further discussion on Petrohawk, please refer to **Note 13**. **PENDING TRANSACTION.**

4.) Brookshire Dome, Waller County, Texas - The Company reduced its working interest in its unevaluated Brookshire Dome leasehold from 40% to 25% and received approximately $747,000. There were no proved reserves associated with this acreage. In 2003, the Company further reduced its working interest in the unevaluated properties from 25% to 6.25% in exchange for a 12.5% carried interest in two deep exploration wells, one of which was drilled in 2003 and a dry hole, and a 6.25% carried interest in four shallow exploration wells. The Company retained its existing working interests in all producing properties including any surrounding acreage.

5.) Mid-Continent region, Oklahoma and Kansas - Various interests were sold in several transactions during the third quarter. The interests sold were in non-core marginal producing properties. The proved reserves associated with these properties represented less than 1% of the Company s total proved reserves. Total proceeds received from these sales were approximately $317,300.

In June 2001, the Company purchased additional working interests in certain oil and gas properties located in the Brookshire Dome area, Waller County Texas, in which it had existing working interests, for approximately $726,600. However, certain existing working interest owners in these properties exercised their preferential right to purchase their pro-rata share of the interests originally purchased by the Company. Upon the exercise of this right in August 2001, the Company was reimbursed by the other owners approximately $454,100 of its original acquisition cost. The Company s net acquisition cost, after reimbursement, was approximately $272,500 for an approximate 11.71% working interest. The proved reserves associated with this acquisition were less than 1% of the Company s total proved reserves.

Also in June 2001, the Company sold its 40% working interests in certain oil and gas properties, which represented less than 1% of the Company s proved reserves, for $710,000. The properties were located in Pecos County, Texas.

In August 2001, the Company acquired an additional 15% working interest in its Brookshire Dome, Waller County, Texas leasehold acreage and producing properties for approximately $580,000. After the effect of the acquisition, the Company s total working interest in this prospect is approximately 40%, subject to a 10% back-in interest which reverts to the seller after the project payout, as defined in the purchase and sale agreement.

In December 2001, the Company sold a portion of its interests in two unevaluated properties, located in Jackson County and Galveston County, Texas, for $356,000. The Company retained an approximate 16% interest in its Matterhorn, Jackson County prospect and an approximate 34% interest in its Sara White, Galveston County prospect. Both prospects, which were drilling at December 31, 2001, were subsequently deemed to be dry holes.

Oil and gas properties - The capitalized costs at year-end and costs incurred in oil and gas producing activities during the years were as follows:

		United States		Foreign		Total
2003 Capitalized costs:						
Evaluated properties	$	76,906,831	$	1,810,549	$	78,717,380
Unevaluated properties		1,294,212				1,294,212
		78,201,043		1,810,549		80,011,592
Accumulated depreciation, depletion, amortization and impairment (1)		(37,929,567)		(1,810,549)		(39,740,116)
Net capitalized costs	$	40,271,476	$		$	40,271,476
Cost incurred:						
Property acquisition (2)	$	259,782	$		$	259,782
Exploration		920,232		349		920,581
Development (3)		3,340,883				3,340,883
Total costs incurred	$	4,520,897	$	349	$	4,521,246
2002 Capitalized costs:						
Evaluated properties	$	69,226,520	$	1,680,921	$	70,907,441
Unevaluated properties		4,453,326		129,279		4,582,605
		73,679,846		1,810,200		75,490,046
Accumulated depreciation, depletion, amortization and impairment (4)		(33,452,175)		(1,681,270		