ABRAXAS PETROLEUM CORP
Form 424B3
July 15, 2004

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to Prospectus dated August 11, 2003. | Registration Statement No. 333-103027

ABRAXAS PETROLEUM CORPORATION

11 1/2% Secured Notes due 2007, Series A

6,592,699 Shares of Abraxas Common Stock

We are supplementing the Prospectus dated August 11, 2003, the Prospectus Supplement No. 1 dated August 15, 2003, the Prospectus Supplement No. 2 dated November 20, 2003, and the Prospectus Supplement No. 3 dated February 27, 2004, to add certain information contained in our Annual Report on Form 10-K for the fiscal year ended December 31, 2003 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2004. This prospectus supplement is not complete without, and may not be delivered or utilized except in connection with, the Prospectus dated August 11, 2003, Prospectus Supplement No. 1, Prospectus Supplement No. 2 and Prospectus Supplement No. 3, with respect to the securities described above, including any amendments or supplements thereto.

This prospectus supplement, together with the prospectuses listed above, is to be used by certain holders of the above-referenced securities or by their transferees, pledges, donees or their successors in connection with the offer and sale of the above referenced securities. This prospectus supplement should be read in conjunction with the prospectus dated August 11, 2003, Prospectus Supplement No. 1 dated August 15, 2003, Prospectus Supplement No. 2 dated November 20, 2003, and Prospectus Supplement No. 3 dated February 27, 2004, that are to be delivered with this prospectus supplement. All capitalized terms used but not defined in this prospectus supplement shall have the meanings given them in the prospectus dated August 11, 2003.

You should carefully consider the risk factors beginning on page 12 of the prospectus dated August 11, 2003, and the risk factors beginning on page S-6 of this prospectus supplement, before making an investment in the notes or common stock.

Neither the SEC nor any state securities commission has approved or disapproved of the notes or the Abraxas common stock or determined if this prospectus supplement or the prospectus dated August 11, 2003 is accurate or complete. Any representation to the contrary is a criminal offense.

July 15, 2004

The following information is added to the prospectus dated August 11, 2003:

1. INFORMATION ADDED FROM
ANNUAL REPORT OF FORM 10-K FOR THE YEAR ENEDE
DECEMBER 31, 2003

2. INFORMATION ADDED FROM
QUARTERLY REPORT OF FORM 10-Q FOR THE THREE MONTHS ENDED
MARCH 31, 2004

1. INFORMATION ADDED FROM
ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED
DECEMBER 31, 2003

FORWARD-LOOKING INFORMATION

We make forward-looking statements throughout this document. Whenever you read a statement that is not simply a statement of historical fact (such as when we describe what we "believe," "expect" or "anticipate" will occur or what we "intend" to do, and other similar statements), you must remember that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this document is generally located in the material set forth under the headings "Risk Factors," "Business," and "Management's Discussion and Analysis of Financial Condition and Results of Operations" but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management's reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- our high debt level;
- our ability to raise capital;
- our limited liquidity;
- economic and business conditions;
- price and availability of alternative fuels;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- our success in development, exploitation and exploration activities;
- planned capital expenditures;
- prices for crude oil and natural gas;
- declines in our production of crude oil and natural gas;
- our acquisition and divestiture activities;
- results of our hedging activities; and
- other factors discussed elsewhere in this document.

Business

General

Abraxas Petroleum Corporation is an independent energy company engaged primarily in the acquisition, development, exploitation and production of crude oil and natural gas. Our principal means of growth has been through the acquisition and subsequent development and exploitation of producing properties. As a result of our historical acquisition activities, we believe that we have a substantial inventory of low risk exploitation and development opportunities, the successful completion of which is critical to the maintenance and growth of our current production levels.

In this document, PV-10 means estimated future net revenue discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the Securities and Exchange Commission. A Mcf is one thousand cubic feet of natural gas. MMcf is used to designate one million cubic feet of natural gas and Bcf refers to one billion cubic feet of natural gas. Mcfe means thousands of cubic feet of natural gas equivalents, using a conversion ratio of one barrel of crude oil to six Mcf of natural gas. MMcfe means millions of cubic feet of natural gas equivalents and Bcfe means billions of cubic feet of natural gas equivalents. MMBtu means million British Thermal Units. The term Bbl means one barrel of crude oil or

natural gas liquids and MBbls is used to designate one thousand barrels of crude oil or natural gas liquids.

Our principal areas of operation are Texas and western Canada. At December 31, 2003, we owned interests in 263,730 gross acres (183,354 net acres), and operated properties accounting for approximately 88% of our PV-10, affording us substantial control over the timing and incurrence of operating and capital expenditures. At December 31, 2003 estimated total proved reserves were 121.1 Bcfe with an aggregate PV-10 of $216.8 million. During 2003, we continued exploitation activities on our U.S. and Canadian properties. We participated in the drilling of 24 gross (11.8 net) wells with 23 gross (11.3 net) being successful. The Company invested $18.3 million in capital spending on these activities during 2003. At the end of 2003, as a result of these activities, our average daily production was approximately 24 MMcfe per day which represented a 26% increase from the daily production rate at the beginning of the year (excluding production from the Canadian properties sold in January 2003).

In January 2003, we completed the following restructuring transactions:

- The closing of the sale of the capital stock of our wholly-owned subsidiaries Canadian Abraxas Petroleum Limited, referred to herein as Canadian Abraxas, and Grey Wolf Exploration Inc., referred to herein as Old Grey Wolf, to a Canadian royalty trust for approximately $138 million.

- The closing of a new senior credit agreement consisting of a term loan facility of $4.2 million and a revolving credit facility of up to $50 million with an initial borrowing base of $49.9 million, of which $42.5 million was used to fund the exchange offer described below and the remaining availability funded the continued development of our existing crude oil and natural gas properties.

- The closing of an exchange offer, pursuant to which Abraxas paid $264 in cash and issued $610 principal amount of new 11 1/2 % Secured Notes due 2007, Series A, referred to herein as New Notes, and 31.36 shares of Abraxas common stock for each $1,000 in principal amount of the outstanding 11 1/2 % Senior Secured Notes due 2004, Series A, and 11 1/2 % Senior Notes due 2004, Series D, issued by Abraxas and Canadian Abraxas, which were tendered and accepted in the exchange offer. An aggregate of approximately $179.9 million in principal amount of the notes were tendered in the exchange offer and the remaining $11.1 million of notes not tendered were redeemed.

- o The repayment of Abraxas' 12? % Senior Secured Notes due 2003, principal amount of $63.5 million, plus accrued interest.

- o The repayment of Old Grey Wolf's senior secured credit facility with Mirant Canada Energy Capital Ltd. (Mirant Canada Facility) in the amount of approximately $46.3 million.

As a result of these transactions, we reduced the principal amount of our total outstanding long-term debt from approximately $300 million at December 31, 2002 to approximately $156.4 million at January 23, 2003 ($184.6 million at December 31, 2003) and reduced our annual cash interest payment from approximately $34 million to approximately $4 million, assuming that, as required under the senior credit agreement, Abraxas continues to issue additional notes in lieu of cash interest payments on the New Notes.

On February 23, 2004, we entered into an amendment to our existing senior credit agreement providing for two revolving credit facilities and a new non-revolving credit facility. Subject to earlier termination on the occurrence of events of default or other events, the stated maturity date for these credit facilities is February 1, 2007. We have included a detailed summary of our amended senior credit agreement in "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Long-Term Indebtedness - Senior Credit Agreement".

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices of, and demand for, crude oil and natural gas. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our crude oil and natural gas production and the level of such production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other crude oil-producing and natural gas-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices of crude oil and natural gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenue, profitability and cash flow from operations. You should read the discussion under "Risk Factors - Crude oil and natural gas prices and their volatility could adversely effect our revenues, cash flows and profitability" and "Management's Discussion and Analysis of Financial Condition and Results of Operations - Critical Accounting Policies" for more information relating to the effects on us of decreases in crude oil and natural gas prices.

In order to manage our exposure to price risks in the marketing of our crude oil and natural gas, from time to time we have entered into fixed price delivery contracts, financial swaps and crude oil and natural gas futures contracts as hedging devices. To ensure a fixed price for future production, we may sell a futures contract and thereafter either (i) make physical delivery of crude oil or natural gas to comply with such contract or (ii) buy a matching futures contract to unwind our futures position and sell our production to a customer. These contracts may expose us to the risk of financial loss in certain circumstances, including instances where production is less than expected, our customers fail to purchase or deliver the contracted quantities of crude oil or natural gas, or a sudden, unexpected event materially impacts crude oil or natural gas prices. These contracts may also restrict our ability to benefit from unexpected increases in crude oil and natural gas prices. You should read the discussion under "Management's Discussion and Analysis of Financial Condition And Results of Operations -- Liquidity and Capital Resources," and "Quantitative and Qualitative Disclosures about Market Risk; Commodity Price Risk" for more information regarding our historical hedging activities.

Substantially all of our crude oil and natural gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2003 three purchasers accounted for approximately 80% of our United States crude oil and natural gas sales and three customers accounted for approximately 91% of our crude oil and natural gas sales in Canada. We believe that there are numerous other companies available to purchase our crude oil and natural gas and that the loss of one or more of these purchasers would not materially affect our ability to sell crude oil and natural gas. The prices we realize for the sale of our crude oil and natural gas are subject to our hedging activities. You should read the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources" and "Quantitative and Qualitative Disclosures about Market Risk; Commodity Price Risk" for more information regarding our historical hedging activities.

Risk Factors

Risks Related to Our Company

Our reduced operating cash flow resulting from the sale of Canadian Abraxas and Old Grey Wolf may put significant strain on our liquidity and cash position. Our reduced operating cash flow and resulting limited liquidity has caused us, and the limitations imposed by our senior credit agreement and the New Notes will cause us, to reduce capital expenditures, including exploitation and development projects. These reductions will limit our ability to replenish our depleting reserves, which could negatively impact our cash flow from operations and results of operations in the future. In addition, under the terms of the New Notes, we are required, to the extent permitted, to pay down debt under our senior credit agreement and, if permitted, the New Notes, with our cash flow which is not required to pay our capital expenditures or make cash interest and tax payments.

The effects of our reduced operating cash flow will be exacerbated by our high level of debt, which will affect our operations in several important ways, including:

- A portion of our cash flow from operations could be required to make principal and interest payments on our outstanding indebtedness and may not be available for other purposes, including developing our properties;

- The covenants contained in the indenture governing the New Notes and in the senior credit agreement will limit our ability to borrow additional funds or to dispose of assets or use the proceeds of any asset sales and may affect our flexibility in planning for, and reacting to, changes in our business; and

- Our debt level may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, interest payments, scheduled principal payments, general corporate purposes or other purposes.

Our limited liquidity and restrictions on uses of cash dictated by both our senior credit agreement and the New Notes, combined with our high debt levels, may hinder our ability to satisfy the substantial capital requirements related to our operations. The success of our future operations will require us to make substantial capital expenditures for the exploitation, development and production of crude oil and natural gas.

Under the terms of the senior credit agreement and the New Notes, Abraxas is subject to cash and expenditures covenants including limitations on capital expenditures. These limitations will have the effect of limiting our ability to develop our crude oil and natural gas properties because much of our cash flow may be used for debt service. As a result, our ability to replace production may be limited. You should read the discussion under "Our ability to replace production with new reserves is highly dependent on acquisitions or successful development and exploration activities" for more information regarding the risks associated with limitations on our ability to develop our crude oil and natural gas properties.

Hedging transactions may limit our potential gains. Under the terms of the senior credit agreement, we are required to maintain commodity price hedging positions on not less than 40% and not more than 75% of our estimated production for a rolling six-month period. As of December 31, 2003 we had floors in place as follows:

Time Period	Notional Quantities	Price
March 1, 2003 - February 29, 2004	5,000 MMBtu of natural gas production per day	Floor of $4.50
March 1, 2004 - April 30, 2004	2,000 MMBtu of natural gas production per day	Floor of $4.00
March 1, 2004 - April 30, 2004	500 Bbls of crude oil production per day	Floor of $22.00
May 2004	2,000 MMbtu of natural gas production per day	Floor of $4.00
May 2004	500 Bbls of crude oil production per day	Floor of $22.00
June 2004	800 Bbls of crude oil production per day	Floor of $22.00
July 2004	2,000 MMbtu of natural gas production per day	Floor of $4.00
July 2004	500 Bbls of crude oil production per day	Floor of $22.00

Subsequent to year-end, we have entered into additional agreements similar to those scheduled above (floors) in volume amounts sufficient to reach the 40% threshold required by our senior credit agreement. We anticipate continuing to purchase similar floors in the future to satisfy our requirements under the senior credit agreement.

We cannot assure you that our hedging transactions will reduce risk or minimize the effect of any decline in crude oil or natural gas prices. Any substantial or extended decline in crude oil or natural gas prices would have a material adverse effect on our business and financial results. Hedging activities may limit the risk of declines in prices, but such arrangements may also limit, and have in the past limited, additional revenues from price increases. In addition, such transactions may expose us to risks of financial loss under certain circumstances, such as:

- production being less than expected; or

- price differences between delivery points for our production and those in our hedging agreements increasing.

In 2001, 2002 and 2003, we experienced hedging losses of $12.1 million, $3.2 million and $842,000, respectively.

Our ability to replace production with new reserves is highly dependent on acquisitions or successful development and exploitation activities. The rate of production from crude oil and natural gas properties declines as reserves are depleted. Our proved reserves will decline as reserves are produced unless we acquire additional properties containing proved reserves, conduct successful exploration, exploitation and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. Our future crude oil and natural gas production is therefore highly dependent upon our level of success in acquiring or finding additional reserves. While we have had some success in pursuing these activities, we have not been able to fully replace the production volumes lost from natural field declines and property sales. We have implemented a number of measures to conserve our cash resources, including postponement of exploration and development projects. However, while these measures will conserve our cash resources in the near term, they will also limit our ability to replenish our depleting reserves, which could negatively impact our cash flow from operations in the future. The terms of our senior credit agreement and the new notes limit our capital expenditures which will further limit our ability to replenish our reserves and replace production. Further, in addition to the effects of our limited liquidity, our operations may be curtailed, delayed or cancelled by other factors, such as title problems, weather, compliance with governmental regulations, mechanical problems or shortages or delays in the delivery of equipment. We cannot assure you that our exploration and development activities will result in increases in reserves.

Use of our net operating loss carryforwards may be limited. At December 31, 2003, Abraxas had, subject to the limitation discussed below, $100.6 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire from 2003 through 2022 if not utilized. In connection with the January 2003 transactions described in Note 2, in Notes to Consolidated Financial Statements, certain of the loss carryforwards were utilized.

As to a portion of the U.S. net operating loss carryforwards, the amount of such carryforwards that we can use annually is limited under U.S. tax law. Additionally, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, Abraxas has established a valuation allowance of $99.1 million and $76.1 million for deferred tax assets at December 31, 2002 and 2003, respectively.

Crude oil and natural gas prices and their volatility could adversely affect our revenue, cash flows, profitability and growth. Our revenue, cash flows, profitability and future rate of growth depend substantially upon prevailing prices for crude oil and natural gas. Natural gas prices affect us more than crude oil prices because most of our production and reserves are natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. In addition, we may have ceiling limitation write-downs if prices decline. For example, during the second quarter of 2002, we had a ceiling limitation write down of approximately $116.0 million. Lower prices may also reduce the amount of crude oil and natural gas that we can produce economically.

We cannot predict future crude oil and natural gas prices. Factors that can cause price fluctuations include:

- changes in supply and demand for crude oil and natural gas;
- weather conditions;
- the price and availability of alternative fuels;

- political and economic conditions in oil producing countries, especially those in the Middle East; and
- overall economic conditions.

In addition to decreasing our revenue and cash flow from operations, low or declining crude oil and natural gas prices could have additional material adverse effects on us, such as:

- reducing the overall volumes of crude oil and natural gas that we can produce economically;
- causing a ceiling limitation write-down;
- increasing our dependence on external sources of capital to meet our liquidity requirements;
- reducing our borrowing base under our senior credit agreement; and
- impairing our ability to obtain needed equity capital.

Lower crude oil and natural gas prices increase the risk of ceiling limitation write-downs. We use the full cost method to account for our crude oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop crude oil and natural gas properties. Under full cost accounting rules, the net capitalized cost of crude oil and natural gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties, as adjusted for asset retirement obligations. If net capitalized costs of crude oil and natural gas properties, as adjusted for asset retirement obligations, exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and earnings. The risk that we will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher crude oil and natural gas prices may have increased the ceiling applicable to the subsequent period.

We have incurred ceiling limitation writedowns in the past. At June 30, 2002, for example, we recorded a ceiling limitation writedown of $116 million. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future.

Estimates of our proved reserves and future net revenue are uncertain and inherently imprecise. This document contains estimates of our proved crude oil and natural gas reserves and the estimated future net revenue from such reserves. The process of estimating crude oil and natural gas reserves is complex and involves decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data. Therefore, these estimates are imprecise.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this document. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues referred to in this document is the current market value of our estimated crude oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the period of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the end of the year of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses

from the development and production of crude oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with us or the crude oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

The estimates of our reserves are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of crude oil and natural gas reserves, future net revenue from proved reserves and the PV-10 thereof for the crude oil and natural gas properties described in this document are based on the assumption that future crude oil and natural gas prices remain the same as crude oil and natural gas prices at December 31, 2003. The sales prices as of such date used for purposes of such estimates were $31.03 per Bbl of crude oil, $27.19 per Bbl of NGLs and $5.05 per Mcf of natural gas. This compares with $29.69 per Bbl of crude oil, $18.89 per Bbl of NGLs and $3.79 per Mcf of natural gas as of December 31, 2002. These estimates also assume that we will make future capital expenditures of approximately $50.4 million in the aggregate, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

We have experienced recurring net losses. The following table shows the losses we had in 1998, 1999, 2001 and 2002:

	Years Ended December 31,			
	1998	1999	2001	2002

Net loss	$(84.0)	$(36.7)	$(19.7)	$ (118.5)

While we had net income in 2000 of $8.4 million, if the significant gain on the sale of an interest in a partnership were excluded, we would have experienced a net loss for the year of ($25.5) million. Similarly, while we had net income of $55.9 million in 2003, if the gain on the sale of our Canadian subsidiaries were excluded, we would have experienced a net loss for the year of ($13.0) million. We cannot assure you that we will become profitable in the future.

The marketability of our production depends largely upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. The marketability of our production depends in part upon processing facilities. Transportation space on such gathering systems and pipelines is occasionally limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. Our access to transportation options can also be affected by U.S. federal and state and Canadian regulation of crude oil and natural gas production and transportation, general economic conditions, and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the financial impact on us could be substantial and adversely affect our ability to produce and market crude oil and natural gas.

Our Canadian operations are subject to the risks of currency fluctuations and in some instances economic and political developments. We conduct operations in Canada. The expenses of such operations are payable in Canadian dollars while most of the revenue from crude oil and natural gas sales is based upon U.S. dollar price indices. As a result, Canadian operations are subject to the risk of fluctuations in the relative values of the Canadian and U.S. dollars. We are also required to recognize foreign currency translation gains or losses related to any debt issued by our Canadian subsidiary because the debt is denominated in U.S. dollars and the functional currency of such subsidiary is the Canadian dollar. Our foreign operations may also be adversely affected by local political and economic developments, royalty and tax increases and other foreign laws or policies, as well as U.S. policies affecting trade, taxation and investment in other countries.

We depend on our key personnel. We depend to a large extent on Robert L.G. Watson, our Chairman of the Board, President and Chief Executive Officer, for our management and business and financial contacts. The unavailability of Mr. Watson could have a materially adverse effect on our business. Mr. Watson has a three-year employment contract with Abraxas commencing on December 21, 1999, which automatically renews thereafter for successive one-year periods unless

Abraxas gives 120 days notice prior to the expiration of the original term or any extension thereof of its intention not to renew the employment agreement. Our success is also dependent upon our ability to employ and retain skilled technical personnel. While we have not experienced difficulties in employing or retaining such personnel, our failure to do so in the future could adversely affect our business.

Risks Related to Our Industry

Our operations are subject to numerous risks of crude oil and natural gas drilling and production activities. Our crude oil and natural gas drilling and production activities are subject to numerous risks, many of which are beyond our control. These risks include the following:

- that no commercially productive crude oil or natural gas reservoirs will be found;
- that crude oil and natural gas drilling and production activities may be shortened, delayed or canceled; and
- that our ability to develop, produce and market our reserves may be limited by:
- title problems,
- weather conditions,
- compliance with governmental requirements, and
- mechanical difficulties or shortages or delays in the delivery of drilling rigs and other equipment.

In the past, we have had difficulty securing drilling equipment in certain of our core areas. We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for crude oil and natural gas may be unprofitable. Dry holes and wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. In addition, our properties may be susceptible to hydrocarbon draining from production by other operations on adjacent properties.

Our industry also experiences numerous operating risks. These operating risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these industry operating risks occur, we could have substantial losses. Substantial losses also may result from injury or loss of life, severe damage to or destruction of property, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

We operate in a highly competitive industry which may adversely affect our operations. We operate in a highly competitive environment. Competition is particularly intense with respect to the acquisition of desirable undeveloped crude oil and natural gas properties. The principal competitive factors in the acquisition of such undeveloped crude oil and natural gas properties include the staff and data necessary to identify, investigate and purchase such properties, and the financial resources necessary to acquire and develop such properties. We compete with major and independent crude oil and natural gas companies for properties and the equipment and labor required to develop and operate such properties. Many of these competitors have financial and other resources substantially greater than ours.

The principal resources necessary for the exploration and production of crude oil and natural gas are leasehold prospects under which crude oil and natural gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of crude oil and natural gas operations. We must compete for such resources with both major crude oil and natural gas companies and independent operators. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our operations in the immediate future, we cannot assure you that such materials and resources will be available to us.

We face significant competition for obtaining additional natural gas supplies for gathering and processing operations, for marketing NGLs, residue gas, helium, condensate and sulfur, and for transporting natural gas and liquids. Our principal competitors include major integrated oil companies and their marketing affiliates and national and local gas gatherers, brokers, marketers and distributors of varying sizes, financial resources and experience. Certain competitors, such as major crude oil and natural gas companies, have capital resources and control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas.

Our crude oil and natural gas operations are subject to various U.S. federal, state and local and Canadian federal and provincial governmental regulations that materially affect our operations. Matters regulated include discharge permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of crude oil and natural gas, these agencies have restricted the rates of flow of crude oil and natural gas wells below actual production capacity. Federal, state, provincial and local laws regulate production, handling, storage, transportation and disposal of crude oil and natural gas, by-products from crude oil and natural gas and other substances and materials produced or used in connection with crude oil and natural gas operations. To date, our expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant. We believe that we are in substantial compliance with all applicable laws and regulations. However, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Regulation of Crude Oil and Natural Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our operations are affected from time to time in varying degrees by political developments and federal, state, provincial and local laws and regulations. In particular, crude oil and natural gas production operations and economics are, or in the past have been, affected by industry specific price controls, taxes, conservation, safety, environmental, and other laws relating to the petroleum industry, by changes in such laws and by constantly changing administrative regulations.

Price Regulations

In the past, maximum selling prices for certain categories of crude oil, natural gas, condensate and NGLs in the United States were subject to significant federal regulation. At the present time, however, all sales of our crude oil, natural gas, condensate and NGLs produced in the United States under private contracts may be sold at market prices. Congress could, however, reenact price controls in the future. If controls that limit prices to below market rates are instituted, our revenue would be adversely affected.

Crude oil and natural gas exported from Canada is subject to regulation by the National Energy Board ("NEB") and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the government of Canada. Crude oil and natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB license and Governor in Council approval.

The provincial governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from these provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and marketing considerations.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of the United States, Canada and Mexico became effective. In the context of energy resources, Canada remains free to determine whether exports to

the U.S. or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports. The Texas Railroad Commission has recently become the lead agency for Texas for coordinating permits governing Texas to Mexico cross border pipeline projects. The availability of selling natural gas into Mexico may substantially impact the interstate natural gas market on all producers in the coming years.

United States Natural Gas Regulation

Historically, the natural gas industry as a whole has been more heavily regulated than the crude oil or other liquid hydrocarbons market. Most regulations focused on transportation practices. Currently, the Federal Energy Regulatory Commission (the "FERC"), requires each interstate pipeline to, among other things, "unbundle" its traditional bundled sales services and create and make available on an open and nondiscriminatory basis numerous constituent services (such as gathering services, storage services, firm and interruptible transportation services, and standby sales and natural gas balancing services), and to adopt a new ratemaking methodology to determine appropriate rates for those services. To the extent the pipeline company or its sales affiliate markets natural gas as a merchant, it does so pursuant to private contracts in direct competition with all of the sellers, such as us; however, pipeline companies and their affiliates are not required to remain "merchants" of natural gas, and most of the interstate pipeline companies have become "transporters only," although many have affiliated marketers

Transportation pipeline availability and shipping cost are major factors affecting the production and sale of natural gas. Our physical sales of natural gas are affected by the actual availability, terms and cost of pipeline transportation. The price and terms for access onto the pipeline transportation systems remain subject to extensive Federal regulation. Although FERC does not directly regulate our production and marketing activities, it does affect how buyers and sellers gain access to and use of the necessary transportation facilities and how we and our competitors sell natural gas in the marketplace. FERC continues to review and modify its regulations regarding the transportation of natural gas. For example, the FERC has recently begun a broad review of its natural gas transportation regulations, including how its regulations operate in conjunction with state proposals for natural gas marketing restructuring and in the increasingly competitive marketplace for all post-wellhead services related to natural gas.

In recent years the FERC also has pursued a number of important policy initiatives which could significantly affect the marketing of natural gas in the United States. Most of these initiatives are intended to enhance competition in natural gas markets. FERC rules encouraging "spin downs," or the breakout of unregulated gathering activities from regulated transportation services, may have the adverse effect of increasing the cost of doing business on some in the industry, including us, as a result of the geographic monopolization of certain facilities by their new, unregulated owners. As to all of the FERC initiatives, the ongoing, or, in some instances, preliminary and evolving nature makes it impossible at this time to predict their ultimate impact on our business. However, we do not believe that any FERC initiatives will affect us any differently than other natural gas producers and marketers with which we compete.

FERC decisions involving onshore facilities are more liberal in their reliance upon traditional tests for determining what facilities are "gathering" and therefore exempt from federal regulatory control. In many instances, what was in the past classified as "transmission" may now be classified as "gathering." We ship certain of our natural gas through gathering facilities owned by others, including interstate pipelines, under existing long term contractual arrangements. Although FERC decisions create the potential for increasing the cost of shipping our natural gas on third party gathering facilities, our shipping activities have not been materially affected by these decisions.

In summary, all of the FERC activities related to the transportation of natural gas result in improved opportunities to market our physical production to a variety of buyers and market places, while at the same time increasing access to pipeline transportation and delivery services. Additional proposals and proceedings that might affect the natural gas industry in the United States are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The crude oil and natural gas industry historically has been very heavily regulated; thus there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue indefinitely into the future.

State and Other Regulation

All of the jurisdictions where we own producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas. These include provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells and provisions relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units on an acreage basis and the density of wells which may be drilled and the unitization or pooling of crude oil and natural gas properties. In this regard, some states and provinces allow the forced pooling or integration of tracts to facilitate exploration while other states and provinces rely on voluntary pooling of lands and leases. In addition, state and provincial conservation laws establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. Some states, such as Texas and Oklahoma, have, in recent years, reviewed and substantially revised methods previously used to make monthly determinations of allowable rates of production from fields and individual wells. The effect of all of these conservation regulations is to limit the speed, timing and amounts of crude oil and natural gas we can produce from our wells, and to limit the number of wells or the location at which we can drill.

State and provincial regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take or service requirements, but does not generally entail rate regulation. In the United States, natural gas gathering has received greater regulatory scrutiny at both the state and federal levels in the wake of the interstate pipeline restructuring under FERC. For example, the Texas Railroad Commission enacted a Natural Gas Transportation Standards and Code of Conduct to provide regulatory support for the State's more active review of rates, services and practices associated with the gathering and transportation of natural gas by an entity that provides such services to others for a fee, in order to prohibit such entities from unduly discriminating in favor of their affiliates.

For those operations on U.S. Federal or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various federal agencies. In addition, in the United States, the Minerals Management Service ("MMS") prescribes or severely limits the types of costs that are deductible transportation costs for purposes of royalty valuation of production sold off the lease. In particular, MMS prohibits deduction of costs associated with marketer fees, cash out and other pipeline imbalance penalties, or long-term storage fees. Further, the MMS has been engaged in a process of promulgating new rules and procedures for determining the value of crude oil produced from federal lands for purposes of calculating royalties owed to the government. The crude oil and natural gas industry as a whole has resisted the proposed rules under an assumption that royalty burdens will substantially increase. We cannot predict what, if any, effect any new rule will have on our operations.

Canadian Royalty Matters

In addition to Canadian federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties

payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type and quality of the petroleum product produced.

From time to time the governments of Alberta and British Columbia, the provinces where almost all of New Grey Wolf's production is located, have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging crude oil and natural gas exploration or enhanced planning projects. All of New Grey Wolf's production is from oil and gas rights which have been granted by the Provinces.

The Province of Alberta requires the payment from lessees of oil and gas rights of annual rental payments as well as royalty payments. Regulations made pursuant to the Mines and Minerals Act (Alberta) provide various incentives for exploring and developing crude oil reserves in Alberta. Crude oil produced from horizontal extensions commenced at least five years after the well was originally spudded may qualify for a royalty reduction. An 8,000 cubic meters exemption is available to production from a well that has not produced for a 12-month period prior to January 31, 1993 or 24 consecutive months following such date. In addition, crude oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992, is entitled to a 12-month royalty exemption (to a maximum of CDN $1 million). Crude oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

The Alberta government classifies conventional crude oil into three categories, being Old Oil, New Oil and Third Tier Oil. Each have a base royalty rate of 10%. The rate caps on the categories are 25% for oil from crude oil pools discovered after September 30, 1992, being the Third Tier Oil, 30% for oil from pools or pool extensions discovered after April 1, 1974, from wells drilled or deepened after October 31, 1991 or from reactivated wells and which are not Third Tier Oil, and 35% for Old Oil.

Effective January 1, 1994, the calculation and payment of natural gas royalties became subject to a simplified process. The royalty reserved to the Crown, subject to various incentives, is between 15% or 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of crude oil or natural gas is entitled to credit against the royalties payable to the Crown by virtue of the Alberta Royalty Tax Credit ("ARTC") program. The ARTC program is based on a price-sensitive formula, and the ARTC rate currently varies between 75% for prices for crude oil at or below CDN $100 per cubic meter (CDN $15.90 per Bbl) and 35% for prices above CDN $210 per cubic meter (CDN $33.38 per Bbl). The ARTC rate is currently applied to a maximum of CDN $2.0 million of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Producers of crude oil and natural gas in British Columbia are also required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of crude oil and natural gas produced from Crown and freehold lands respectively. British Columbia also classifies conventional crude oil into the three categories of Old Oil, New Oil and Third Tier Oil. The amount payable as a royalty in respect of crude oil depends on the vintage of the crude oil (whether it was produced from a pool discovered before or after October 31, 1975) or a pool in which no well was completed on June 1, 1998), the quantity of crude oil produced in a month and the value of the crude oil. Crude oil produced from a discovery well may be exempt from the payment of a royalty for the first 36 months of production to a maximum production of 72,024 Bbls. The royalty payable on natural gas is determined by a sliding scale based on a classification of the gas based on whether it is conservation gas

(gas associated with marketed oil production) and by drilling and land lease date and on a reference price which is the greater of the amount obtained by the producer and at prescribed minimum price. Conservation gas has a minimum royalty of 8%. The royalty rate ranges from between 9% and 27% for wells drilled on lands issued after May 31, 1998 and before January 1, 2003 and completed within 5 years of the date the lands were issued and between 12% and 27% for wells spudded after May 31, 1998 on lands where rights had been issued as of May 31, 1998.

Environmental Matters

Our operations are subject to numerous federal, state, provincial and local laws and regulations controlling the generation, use, storage, and discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment in connection with drilling, production, and natural gas processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as use of pits and plugging of abandoned wells; restrict injection of liquids into subsurface strata that may contaminate groundwater; and impose substantial liabilities for pollution resulting from our operations. Environmental permits required for our operations may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations and permits, and violations are subject to injunction, civil fines, and even criminal penalties. Our management believes that we are in substantial compliance with current environmental laws and regulations, and that we will not be required to make material capital expenditures to comply with existing laws. Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on us as well as the crude oil and natural gas industry in general, and thus we are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

In the United States, the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as "Superfund," and comparable state statutes impose strict, joint, and several liability on certain classes of persons who are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a disposal site or sites where a release occurred and companies that generated, disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA such persons or companies may be retroactively liable for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is common for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize imposition of substantial civil and criminal penalties for failing to prevent surface and subsurface pollution, as well as to control the generation, transportation, treatment, storage and disposal of hazardous waste generated by crude oil and natural gas operations. Although CERCLA currently contains a "petroleum exclusion" from the definition of "hazardous substance," state laws affecting our operations impose cleanup liability relating to petroleum and petroleum related products, including crude oil cleanups. In addition, although

RCRA regulations currently classify certain oilfield wastes which are uniquely associated with field operations as "non-hazardous," such exploration, development and production wastes could be reclassified by regulation as hazardous wastes thereby administratively making such wastes subject to more stringent handling and disposal requirements.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we utilized standard industry operating and disposal practices at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we owned or leased or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Our operations are also impacted by regulations governing the disposal of naturally occurring radioactive materials ("NORM"). We must comply with the Clean Air Act and comparable state statutes which prohibit the emissions of air contaminants, although a majority of our activities are exempted under a standard exemption. Moreover, owners, lessees and operators of crude oil and natural gas properties are also subject to increasing civil liability brought by surface owners and adjoining property owners. Such claims are predicated on the damage to or contamination of land resources occasioned by drilling and production operations and the products derived there from, and are usually causes of action based on negligence, trespass, nuisance, strict liability and fraud.

United States federal regulations also require certain owners and operators of facilities that store or otherwise handle crude oil, such as us, to prepare and implement spill prevention, control and countermeasure plans and spill response plans relating to possible discharge of crude oil into surface waters. The federal Oil Pollution Act ("OPA") contains numerous requirements relating to prevention of, reporting of, and response to crude oil spills into waters of the United States. For facilities that may affect state waters, OPA requires an operator to demonstrate $10 million in financial responsibility. State laws mandate crude oil cleanup programs with respect to contaminated soil.

Our Canadian operations are also subject to environmental regulation pursuant to local, provincial and federal legislation which generally require operations to be conducted in a safe and environmentally responsible manner. Canadian environmental legislation provides for restrictions and prohibitions relating to the discharge of air, soil and water pollutants and other substances produced in association with certain crude oil and natural gas industry operations, and environmental protection requirements, including certain conditions of approval and laws relating to storage, handling, transportation and disposal of materials or substances which may have an adverse effect on the environment. Environmental legislation can affect the location of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders.

Certain federal environmental laws that may affect us include the Canadian Environmental Assessment Act which ensures that the environmental effects of projects receive careful consideration prior to licenses or permits being issued, to ensure that projects that are to be carried out in Canada or on federal lands do not cause significant adverse environmental effects outside the jurisdictions in which they are carried out, and to ensure that there is an opportunity for public participation in the environmental assessment process; the Canadian Environmental Protection Act ("CEPA") which is the most comprehensive federal environmental statute in Canada, and which controls toxic substances (broadly defined), includes standards relating to the discharge of air, soil and water pollutants, provides for broad enforcement powers and remedies and imposes significant penalties for violations; the National Energy Board Act which can impose certain environmental protection conditions on approvals issued under the Act; the Fisheries Act which prohibits the depositing of a deleterious substance of any type in water frequented by fish or in any place under any condition where such deleterious substance may enter any such water and provides for significant penalties; the Navigable Waters Protection Act which requires any work which is built in, on, over, under, through or across any navigable water to be approved by the Minister of Transportation, and which attracts severe penalties and remedies for non-compliance, including removal of the work.

In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. In addition to consolidating a variety of environmental statutes, the AEPEA also imposes certain new environmental responsibilities on crude oil and natural gas operators in Alberta. The AEPEA sets out environmental standards and compliance for releases, clean-up and reporting. The Act provides for a broad range of liabilities, enforcement actions and penalties.

We are not currently involved in any administrative, judicial or legal proceedings arising under domestic or foreign federal, state, or local environmental protection laws and regulations, or under federal or state common law, which would have a material adverse effect on our financial position or results of operations. Moreover, we maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. A serious incident of pollution may result in the suspension or cessation of operations in the affected area.

We believe that we have obtained and are in compliance with all material environmental permits, authorizations and approvals.

All of our oil and gas wells will require proper plugging and abandonment when they are no longer producing. We post bonds with most regulatory agencies to ensure compliance with our plugging responsibility. Plugging and abandonment operations and associated reclaimation of the surface production site are important components of our environmental management system. We plan accordingly for the ultimate disposition of properties that are no longer producing.

Title to Properties

As is customary in the crude oil and natural gas industry, we make only a cursory review of title to undeveloped crude oil and natural gas leases at the time we acquire them. However, before drilling commences, we require a thorough title search to be conducted, and any material defects in title are remedied prior to the time actual drilling of a well begins. To the extent title opinions or other investigations reflect title defects, we, rather than the seller of the undeveloped property, are typically obligated to cure any title defect at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our crude oil and natural gas properties, some of which are subject to immaterial encumbrances, easements and restrictions. The crude oil and natural gas properties we own are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. We do not believe that any of these encumbrances or burdens will materially affect our ownership or use of our properties.

Employees

As of March 9, 2004, we had 46 full-time employees in the United States, including 3 executive officers, 3 non-executive officers, 1 petroleum engineer, 1 geologist, 5 managers, 1 landman, 11 administrative and support personnel and 21 field personnel. Additionally, we retain contract pumpers on a month-to-month basis. We retain independent geological and engineering consultants from time to time on a limited basis and expect to continue to do so in the future.

As of March 9, 2004, New Grey Wolf had 11 full-time employees, including 4 executive officers, 1 non-executive officer, 2 geologists and, 4 technical and clerical personnel in Canada.

Properties

Primary Operating Areas

Texas

Our U.S. operations are concentrated in South and West Texas with over 99% of the PV-10 of our U.S. crude oil and natural gas properties at December 31, 2003 located in those two regions. We operate 94% of our wells in Texas. During 2003, we drilled a total of six new wells (3.73 net) in Texas with a 100% success rate.

Operations in South Texas are concentrated along the Edwards trend in Live Oak and DeWitt Counties, the Frio/Vicksburg trend in San Patricio County and the Wilcox trend in Goliad County. In total in South Texas we own an average 93% working interest in 43 wells with average production of 239 net Bbls of crude oil and NGLs and 6,210 net Mcf of natural gas per day for the year ended December 31, 2003. As of December 31, 2003 we had estimated net proved reserves in South Texas of 28.6 Bcfe (82% natural gas) with a PV-10 of $57.7 million, 70% of which was attributable to proved developed reserves.

Our West Texas operations are concentrated along the deep Devonian/Montoya/Ellenberger formations and shallow Cherry Canyon sandstones in Ward County and in the Sharon Ridge Clearfork Field in Scurry County. In September 2000, we entered into a farmout agreement with EOG Resources Inc. whereby EOG earned a 75% working interest in Abraxas' then existing Ward County Montoya acreage by paying Abraxas $2.5 million and paying 100% of the cost of the first five wells, the last of which came on line in December 2002. Two wells were drilled in 2003 in which Abraxas was responsible for its pro rata share of drilling and development cost. The farmout agreement terminated in early January 2004 and accordingly, EOG is obligated to reassign all unearned acreage to Abraxas.

In total in West Texas we own an average 74% working interest in 158 wells with average daily production of 338 net Bbls of crude oil and NGLs and 6,887 net Mcf of natural gas per day for the year ended December 31, 2003. As of December 31, 2003, we had estimated net proved reserves in West Texas of 71.1 Bcfe (80% natural gas) with a PV-10 of $103.6 million, 60% of which was attributable to proved developed reserves.

Wyoming

We currently hold over 60,000 contiguous acres in the Powder River Basin in east central Wyoming. The Company has drilled and operates 5 wells in Converse and Niobrara counties that were completed in the Turner and Niobrara formations. We own a 100% working interest in these wells that produced an average of 31 net barrels of crude oil per day in 2003. As of December 31, 2003 we had estimated net proved producing reserves in Wyoming of 68,669 barrels of crude oil with a PV-10 of $280,843.

Western Canada

We own properties in western Canada, consisting primarily of natural gas reserves and undeveloped acreage in the provinces of Alberta and British Columbia. Our Alberta properties are in two concentrated areas; the Caroline field, 60 miles northwest of Calgary and the Peace River Arch area in northwestern Alberta. We entered into a farmout agreement with PrimeWest in connection with the sale of Canadian Abraxas and Old Grey Wolf in January of 2003 to jointly develop these areas in the future. Our other Canadian operations are located in the Ladyfern area of northeast British Columbia. During 2003, we drilled a total of 18 new wells (8.1 net) with a 95% success rate.

As of December 31, 2003 New Grey Wolf had estimated net proved reserves of 21.0 Bcfe (77% natural gas) with a PV-10 of $55.2 million of which 76% was attributable to proved developed reserves. For the year ended December 31, 2003, the Canadian properties produced an average of approximately 111 net Bbls of crude oil and NGLs per day and 2,328 net Mcf of natural gas per day.

Exploratory and Developmental Acreage

Our principal crude oil and natural gas properties consist of non-producing and producing crude oil and natural gas leases, including reserves of crude oil and natural gas in place. The following table indicates our interest in developed and undeveloped acreage as of December 31, 2003:

Developed and Undeveloped Acreage

As of December 31, 2003

	Developed Acreage (1)		Undeveloped Acreage (2)	
	Gross Acres (3)	Net Acres (4)	Gross Acres (3)	Net Acres (4)
Canada	18,238	9,075	155,246	93,866
Texas	23,671	18,978	5,864	4,692
Wyoming	3,200	3,200	57,431	53,519
N. Dakota	-	-	80	24
Total	45,109	31,253	218,621	152,101

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(1) Developed acreage consists of acres spaced or assignable to productive wells.

(2) Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas, regardless of whether or not such acreage contains proved reserves.

(3) Gross acres refers to the number of acres in which we own a working interest.

(4) Net acres represents the number of acres attributable to an owner's proportionate working interest and/or royalty interest in a lease (e.g., a

50% working interest in a lease covering 320 acres is equivalent to 160 net acres).

Productive Wells

The following table sets forth our total gross and net productive wells expressed separately for crude oil and natural gas, as of December 31, 2003:

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State/Country	Productive Wells (1) As of December 31, 2003			
	Crude Oil		Natural Gas	
	Gross(2)	Net(3)	Gross(2)	Net(3)
Canada	29.0	5.1	205.0	17.0
Texas	140.5	112.6	60.5	44.7
Wyoming	5.0	5.0	18.0	-
N. Dakota	1.0	-	-	-
Total	175.5	122.7	283.5	61.7

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(1) Productive wells are producing wells and wells capable of production.
(2) A gross well is a well in which we own an interest. The number of gross wells is the total number of wells in which we own an interest.
(3) A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of our fractional working interest owned in gross wells.

Reserves Information

The crude oil and natural gas reserves of the U.S. operations only have been estimated as of January 1, 2004, January 1, 2003, and January 1, 2002, by DeGolyer and MacNaughton, of Dallas, Texas. The reserves of the Canadian operations as of January 1, 2004 and January 1, 2003 have been estimated by DeGolyer and MacNaughton, and the reserves as of January 1, 2002 were estimated by McDaniel and Associates Consultants Ltd. of Calgary, Alberta. The January 1, 2003 reserves attributable to the Canadian properties which were sold in connection with the sale of Canadian Abraxas and Old Grey Wolf were estimated internally. The January 1, 2004 reserves related to an override which was retained by New Grey Wolf were estimated internally. Crude oil and natural gas reserves, and the estimates of the present value of future net revenues there-from, were determined based on then current prices and costs. Reserve calculations involve the estimate of future net recoverable reserves of crude oil and natural gas and the timing and amount of future net revenues to be received there from. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain.

The following table sets forth certain information regarding estimates of our crude oil, natural gas liquids and natural gas reserves as of January 1, 2002, January 1, 2003 and January 1, 2004:

	Estimated Proved Reserves		
	Proved Developed	Proved Undeveloped	Total Proved

As of January 1, 2002 (1)			
Crude oil (MBbls)	1,980	1,170	3,150
NGLs (MBbls)	3,067	585	3,652
Natural gas (MMcf)	111,243	77,514	188,757
As of January 1, 2003 (2)			
Crude oil (MBbls)	1,782	1,317	3,099
NGLs (MBbls)	1,222	284	1,506
Natural gas (MMcf)	90,374	48,458	138,832
As of January 1, 2004			
Crude oil (MBbls)	2,051	1,578	3,629
NGLs (MBbls)	263	242	505
Natural gas (MMcf)	52,398	43,885	96,284

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(1) Reserves as of January 1, 2002 include 138 MBbls of crude oil, 2,257 MBbls of NGLs and 80,289MMcf of natural gas that were sold in connection with the sale of Canadian Abraxas and Old Grey Wolf in January 2003.

(2) Reserves as of January 1, 2003 include 67 MBbls of crude oil, 1,079 MBbls of NGLs, and 47,066 MMcf of natural gas that were sold in connection with the sale of Canadian Abraxas and Old Grey Wolf in January 2003.

The process of estimating crude oil and natural gas reserves is complex and involves decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data. Therefore, these estimates are imprecise.

Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this document. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues referred to in this annual statement is the current market value of our estimated crude oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the year of the estimate, or alternatively, if prices subsequent to that date have increased, a price near the periodic filing date of the Company's financial statements. Because we use the full cost method to account for our crude oil and natural gas operations, we are susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. At June 30, 2002, we incurred a ceiling test writedown of approximately $116.0 million. A ceiling test writedown does not impact cash flow from operating activities but does reduce our stockholders' equity and reported earnings. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future. For more information regarding the full cost method of accounting, you should read the information under "Management's Discussion and Analysis of Financial Condition and Results of Operation - Critical Accounting Policies."

Actual future prices and costs may be materially higher or lower than the prices and costs as of the end of the year of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of crude oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with us or the crude oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

The estimates of our reserves are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of crude oil and natural gas reserves, future net revenue from proved reserves and the PV-10 thereof for the crude oil and natural gas properties described in this document are based on the assumption that future crude oil and natural gas prices remain the same as crude oil and natural gas prices at December 31, 2003. The average sales prices as of such date used for purposes of such estimates were $31.03 per Bbl of crude oil, $27.19 per Bbl of NGLs and $5.05 per Mcf of natural gas. It is also assumed that we will make future capital expenditures of approximately $50.4 million in the aggregate, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

We file reports of our estimated crude oil and natural gas reserves with the Department of Energy and the Bureau of the Census. The reserves reported to these agencies are required to be reported on a gross operated basis and therefore are not comparable to the reserve data reported herein.

Crude Oil, Natural Gas Liquids, and Natural Gas Production and Sales Prices

The following table presents our net crude oil, net natural gas liquids and net natural gas production, the average sales price per Bbl of crude oil and natural gas liquids and per Mcf of natural gas produced and the average cost of production per BOE of production sold, for the three years ended December 31, 2003.

	2001 (1)	2002 (1)	2003 (1
Crude oil production (Bbls)	454,063	292,264	251,567
Natural gas production (Mcf)	17,495,598	15,452,721	6,189,359
Natural gas liquids production (Bbls)	277,969	242,032	37,258
MMcfe	21,888	18,658	7,922
Average sales price per Bbl of crude oil	$ 24.63	$ 24.34	$ 30.32
Average sales price per Mcf of natural gas (2)	$ 3.20	$ 2.55	$ 4.78
Average sales price per Bbl of natural gas liquids	$ 21.51	$ 17.94	$ 24.47
Average sales price per Mcfe	$ 3.35	$ 2.72	$ 4.81
Average cost of production per			

Mcfe produced (3)	$ 0.85	$ 0.82	$ 1.21

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(1) Includes production for 2001, 2002 and the first 23 days of 2003 for Canadian properties sold in January 2003.
(2) Average sales prices are net of hedging activity.
(3) Crude oil and natural gas were combined by converting crude oil and natural gas liquids to a Mcf equivalent on the basis of 1 Bbl of crude oil and natural gas liquid equals 6 Mcf of natural gas. Production costs include direct operating costs, ad valorem taxes and gross production taxes.

Drilling Activities

The following table sets forth our gross and net working interests in exploratory and development wells drilled during the three years ended December 31, 2003:

	2001		2002	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Exploratory(3)				
Productive(4)				
Crude oil	-	-	1.0	1.0
Natural gas	2.0	1.0	3.0	0.5
Dry holes(5)	1.0	.5	3.0	1.5
Total	3.0	1.5	7.0	3.0
Development(6)				
Productive (4)				
Crude oil	2.0	2.0	-	-

Natural gas	13.0	11.0	14.0	11.8
Dry holes (5)	-	-	1.0	1.0
Total	15.0	13.0	15.0	12.8

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(1) A gross well is a well in which we own an interest.
(2) The number of net wells represents the total percentage of working interests held in all wells (e.g., total working interest of 50% is equivalent to 0.5 net well. A total working interest of 100% is equivalent to 1.0 net well).

(3) An exploratory well is a well drilled to find and produce crude oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be producing crude oil or natural gas in another reservoir, or to extend a known reservoir.
(4) A productive well is an exploratory or a development well that is not a dry hole.
(5) A dry hole is an exploratory or development well found to be incapable of producing either crude oil or natural gas in sufficient quantities to justify completion as a crude oil or natural gas well.
(6) A development well is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting proved crude oil or natural gas reserves.

As of March 9, 2004 we had five wells in process of drilling and completing, two in the U.S. and three in Canada.

Office Facilities

Our executive and administrative offices are located at 500 North Loop 1604 East, Suite 100, San Antonio, Texas 78232, consisting of approximately 12,650 square feet leased until March 2006 at an aggregate base rate of $20,900 per month. We also have an office in Midland, Texas consisting of 570 square feet leased through October 2004 at an aggregate base rate of $380 per month.

New Grey Wolf leases 7,350 square feet of office space in Calgary, Alberta, leased through December 2008 at an aggregate base rate of $13,400 US$ per month.

Other Properties

We own 10 acres of land, an office building, workshop, warehouse and house in Sinton, Texas, 2.8 acres of land, an office building in Scurry County, Texas, 600 acres of fee land in Scurry County, Texas and 160 acres of land in Coke County, Texas. All three properties are used for the storage of tubulars and production equipment. We also own 25 vehicles which are used in the field by employees. We own 2 workover rigs, which are used for servicing our wells.

Legal Proceedings

In 2001, Abraxas and Abraxas Wamsutter L.P. were named as defendants in a lawsuit filed in U.S. District Court in the District of Wyoming. The claim asserts breach of contract, fraud and negligent misrepresentation by Abraxas and Abraxas Wamsutter, L.P. related to the responsibility for year 2000 ad valorem taxes on crude oil and natural gas properties sold by Abraxas and Abraxas Wamsutter, L.P. In February 2002, a summary judgment was granted to the plaintiff in this matter and a final judgment in the amount of $1.3 million was entered. Abraxas has filed an appeal. We believe these charges are without merit. We have established a reserve in the amount of $845,000, which represents our estimated share of the judgment.

In 2003, Abraxas and Leam Drilling Systems each filed suit against the other relating to certain drilling services that Leam contracted to provide Abraxas. Abraxas believes that the services were provided in a grossly negligent manner and that Leam committed fraud. Leam has asserted that Abraxas failed to pay approximately $639,000 for services rendered. The cases are pending in Bexar County and Ward County, Texas.

Additionally, from time to time, we are involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2003, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our operations.

Market for Registrant's Common Equity and Related Stockholder Matters

Market Information

Abraxas common stock began trading on the American Stock Exchange on August 18, 2000, under the symbol "ABP." The following table sets forth certain information as to the high and low bid quotations quoted for Abraxas' common stock on the American Stock Exchange.

	Period	High	Low
2002			
	First Quarter	$ 1.70	$ 0.89
	Second Quarter	1.41	0.52
	Third Quarter	0.98	0.42
	Fourth Quarter	0.80	0.52
2003			
	First Quarter	$ 0.95	$ 0.55
	Second Quarter	1.30	0.61
	Third Quarter	1.11	0.82
	Fourth Quarter	1.32	0.88
2004	First Quarter (Through March 9, 2004)	$ 3.64	$ 1.29

Holders

As of March 9, 2004, we had 36,267,337 shares of common stock outstanding and had approximately 1,597 stockholders of record.

Dividends

We have not paid any cash dividends on our common stock and it is not presently determinable when, if ever, we will pay cash dividends in the future. In addition, the indenture governing the New Notes and our senior credit agreement prohibits the payment of cash dividends and stock dividends on our common stock. You should read the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" for more information regarding the restrictions on our ability to pay dividends.

Recent Sales of Unregistered Securities

On January 23, 2003, we issued approximately $109.7 million in principal amount of New Notes and 5,642,699 shares of Abraxas common stock in connection with the exchange offer. These securities were issued pursuant to the exemption from the registration requirements of the Securities Act of 1933, as amended, under Regulation D. The securities were offered and sold only to accredited investors and to no more than 35 non-accredited investors each of whom Abraxas believed had such knowledge and experience in financial and business matters that he or she was capable of evaluation of the merits and risks on the investment in the New Notes and shares of Abraxas common stock.

On July 29, 2003 Abraxas acquired all of the shares of the capital stock of Wind River Resources Corporation which owned an airplane. The sole shareholder of Wind River was the Company's President. The consideration for the purchase was 106,977 shares of Abraxas common stock and $35,000 in cash. These securities were issued pursuant to the exemption from the registration requirements of the Securities Act of 1933, as amended, under Section 4(2).

Selected Financial Data

The following selected financial data is derived from our Consolidated Financial Statements. The data should be read in conjunction with our Consolidated Financial Statements and Notes thereto, and other financial information included herein.

	Year Ended December 3			
	1999*	2000*	2001*	
	(Dollars in thousands except per s			
Total revenue	$ 66,770	$ 76,600	$ 77,243	$
Net income (loss)	$ (36,680) (3)	$ 8,449 (2)	$ (19,718) (4)	$
Net income (loss) per common share - diluted	$ (5.41)	$ 0.26	$ (0.76)	$
Weighted average shares outstanding - diluted (in thousands)	6,784	22,616	25,789	
Total assets	$ 322,284	$ 335,560	$ 303,616	$
Long-term debt, excluding current maturities	$ 273,421	$ 266,441	$ 285,184	$
Total stockholders' equity (deficit)	$ (9,505)	$ (6,503)	$ (28,585)	$

(1) Includes ceiling limitation write-down of $116.0 million.
(2) Includes gain on sale of partnership interest of $34 million in 2000 and the reclassification of an extraordinary gain on debt extinguishment in 2000 to other income.
(3) Includes ceiling limitation write-down of $19.1 million.
(4) Includes ceiling test write-down of $2.6 million in 2001, based on subsequent (March 22, 2002) realized prices, related to our Canadian operations.
(5) Includes gain on sale of foreign subsidiaries of $ 68.9 million in 2003.

*Data includes Canadian Abraxas and Old Grey Wolf for 1999-2002 and for the first 23 days of 2003 which were sold in January 2003.

Management's Discussion And Analysis Of Financial Condition And Results Of Operations

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. This discussion should be read in conjunction with our Consolidated Financial Statements and the Notes thereto.

General

We are an independent energy company engaged primarily in the acquisition, exploration, exploitation and production of crude oil and natural gas. Our principal means of growth has been through the acquisition and subsequent development and exploitation of producing properties. As a result of our historical acquisition activities, we believe that we have a substantial inventory of low risk exploitation and development opportunities, the successful completion of which is critical to the maintenance and growth of our current production levels.

We have incurred net losses in three of the last five years, and there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors, particularly the following factors which most significantly affect our results of operations:

- o the sales prices of crude oil, natural gas liquids and natural gas;
- o the level of total sales volumes of crude oil, natural gas liquids and natural gas;
- o the availability of, and our ability to raise additional, capital resources and provide liquidity to meet cash flow needs;
- o the level of and interest rates on borrowings; and
- o the level and success of exploitation and development activity.

Commodity Prices and Hedging Activities. Our results of operations are significantly affected by fluctuations in commodity prices. Price volatility in the natural gas market has remained prevalent in the last few years. In January 2001, the market price of natural gas was at its highest level in our operating history and the price of crude oil was also at a high level. However, over the course of 2001 and the beginning of the first quarter of 2002, prices again became depressed, primarily due to the economic downturn. Beginning in March 2002, commodity prices began to increase and continued higher through December 2003. Prices have remained strong during the first part of 2004.

The table below illustrates how natural gas prices fluctuated over the course of 2002 and 2003. The table below contains the last three day average of NYMEX traded contracts price and the prices we realized during each quarter for 2002 and 2003, including the impact of our hedging activities.

Natural Gas Prices by Quarter
(in $ per Mcf)

	Quarter Ended						
	March 31, 2002	June 30, 2002	Sept. 30, 2002	Dec. 31, 2002	March 31, 2003	June 30, 2003	Sept. 3 2003
Index	$ 2.38	$ 3.36	$ 3.28	$ 3.99	$ 6.61	$ 5.51	$ 5
Realized	$ 2.21	$ 2.44	$ 2.08	$ 3.47	$ 5.13	$ 5.11	$ 4

The NYMEX natural gas price on March 9, 2004 was $5.44 per Mcf.

The table below contains the last three day average of NYMEX traded contracts price and the prices we realized during each quarter for 2002 and 2003.

Crude Oil Prices by Quarter
(in $ per Bbl)

	Quarter Ended						
	March 31, 2002	June 30, 2002	Sept. 30, 2002	Dec. 31, 2002	March 31, 2003	June 30, 2003	Sept 20
Index	$ 19.48	$ 26.40	$ 27.50	$ 28.29	$ 33.71	$ 29.87	$ 3
Realized	$ 16.64	$ 23.47	$ 23.47	$ 24.83	$ 33.22	$ 28.53	$ 2

The NYMEX crude oil price on March 9, 2004 was $ 36.28 per Bbl.

We seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. In 2001 and 2002, we experienced hedging losses of $12.1 million and $3.2 million, respectively. In October 2002, all of these hedge agreements expired. We made total payments over the term of these arrangements to various counterparties in the amount of $35.1 million.

Under the terms of our senior credit agreement, we are required to maintain hedging positions with respect to not less than 40% nor more than 75% of our crude oil and natural gas production, on an equivalent basis, for a rolling six month period. As of December 31, 2003, we had the following hedges in place:

Time Period	Notional Quantities	Price
March 1, 2003 - February 29, 2004	5,000 MMBtu of natural gas production per day	Floor of $4.50
March 1, 2004 - April 30, 2004	2,000 MMBtu of natural gas production per day	Floor of $4.00
March 1, 2004 - April 30, 2004	500 Bbls of crude oil production per day	Floor of $22.00
May 2004	2,000 Mmbtu of natural gas production per day	Floor of $4.00
June 2004	500 Bbls of crude oil production per day	Floor of $22.00
June 2004	800 Bbls of crude oil production per day	Floor of $22.00
July 2004	2,000 Mmbtu of natural gas production per day	Floor of $4.00
July 2004	500 Bbls of crude oil production per day	Floor of $22.00

Subsequent to year-end we have entered into additional agreements similar to those scheduled above (floors) in volume amounts sufficient to reach the 40% threshold required by our senior credit agreement. The Company anticipates continuing to purchase similar floors in the future to satisfy our requirements under the senior credit agreement.

Production Volumes. Because our proved reserves will decline as crude oil, natural gas and natural gas liquids are produced, unless we acquire additional properties containing proved reserves or conduct successful exploration and development activities, our reserves and production will decrease. Our ability to acquire or find additional reserves in the near future will be dependent, in part, upon the amount of available funds for acquisition, exploitation and development projects. For more information on the volumes of crude oil, natural gas liquids and natural gas we have produced during 2001, 2002 and 2003, please refer to the information under the caption "Results of Operations" below.

We have budgeted $10 million for drilling expenditures in 2004. Under the terms of our senior credit agreement and our New Notes, we are subject to limitations on capital expenditures. As a result, we will be limited in our ability to replace existing production with new production and might suffer a decrease in the volume of crude oil and natural gas we produce. If crude oil and natural gas prices return to depressed levels or if our production levels continue to decrease, our revenues, cash flow from operations and financial condition will be materially adversely affected. For more information, see "Liquidity and Capital Resources - Current Liquidity Requirements" and "Future Capital Resources."

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital are primarily cash on hand, cash from operating activities, funding under our senior credit agreement and the sale of properties. At March 9, 2004, we had approximately $14.0 million of availability under our senior credit agreement. We may also attempt to raise additional capital through the issuance of debt or equity securities although we cannot assure you that we will be successful in any such efforts.

Borrowings and Interest. As a result of the financial restructuring we completed in January 2003, we reduced our indebtedness from approximately $300.4 million at December 31, 2002 to approximately $184.6 million at December 31, 2003. In addition, we decreased our cash interest expense from $34.2 million during 2002 to $4.3 million during 2003. By decreasing the amount of our indebtedness and required cash interest payments, we reduced the amount of our cash flow from operations needed to pay interest on our indebtedness so that more of our capital resources could be utilized for drilling activities and paying other expenses.

Exploitation and Development Activity. During 2003, we continued exploitation activities on our U.S. properties. We participated in the drilling of 24 gross (11.8 net) wells with 23 gross (11.3 net) being successful. The Company invested $18.3 million in capital spending on these activities during 2003. At the end of 2003, as a result of these activities, our average daily production was approximately 24 MMcfepd, a 26% increase from the daily production rate at the beginning of the year (excluding production from the Canadian properties sold in January 2003).

Outlook for 2004. As a result of final 2003 financial results and current market conditions, Abraxas has updated its operating and financial guidance for year 2004 as follows:

Production:	
BCFE (approximately 80% gas)...............	8-9
Price Differentials (Pre Hedge):	
$ Per Bbl.................................	0.86
$ Per Mcf.................................	0.64
Lifting Costs, $ Per Mcfe....................	1.29
G&A, $ Per Mcfe..............................	0.60
Capital Expenditures ($ Millions)............	10.00

Results of Operations

Selected Operating Data. The following table sets forth certain of our operating data for the periods presented.

	Years Ended December 31, (dollars in thousands, except per unit		
	2001 (1)	2002 (1)	
Operating revenue:			
Crude oil sales	$ 11,184	$ 7,114	$
NGLs sales	5,979	4,343	
Natural gas sales	56,038	39,405	
Gas processing revenue	2,438	2,420	
Rig and other	1,604	1,038	
Total operating revenues	$ 77,243	$ 54,320	$
Operating income (loss)	$ 19,125	$ (110,903)	$
Crude oil production (MBbls)	454.1	292.3	
NGLs production (MBbls)	278.0	242.0	
Natural gas production (MMcf)	17,495.6	15,452.7	
Average crude oil sales price (per Bbl)	$ 24.63	$ 24.34	$
Average NGLs sales price (per Bbl)	$ 21.51	$ 17.94	$
Average natural gas sales price (per Mcf)	$ 3.20	$ 2.55	$

Revenue and average sales prices are net of hedging activities.

(1) Data for 2001, 2002 and the first 23 days of 2003 includes Canadian Abraxas and Old Grey Wolf which were sold in January 2003.

Comparison of Year Ended December 31, 2003 to Year Ended December 31, 2002.

Operating Revenue. During the year ended December 31, 2003, operating revenue from crude oil, natural gas and natural gas liquids sales decreased by $12.8 million from $50.9 million in 2002 to $38.1 million in 2003. The decrease in revenue was primarily due to decreased production volumes, primarily due to the sale of our Canadian subsidiaries in January 2003, which was partially

offset by higher commodity prices realized during the period. Higher commodity prices contributed $16.5 million to crude oil and natural gas revenue while reduced production volumes had a $29.3 million negative impact on revenue. The Canadian properties which were sold in January 2003 contributed $29.3 million to revenues from crude oil and natural gas for the year ended December 31, 2002, compared to $3.1 million in 2003 through the date of sale (January 23, 2003).

Natural gas liquids volumes declined from 242.0 MBbls in 2002 to 37.3 MBbls in 2003 The decline in natual gas liquids volumes was due almost entirely to the sale of our Canadian subsidiaries in January 2003. These properties contributed 232.5 MBbls of natural gas liquids in 2002 compared to 11.7 MBbls during 2003. Crude oil sales volumes declined from 292.3 MBbls in 2002 to 251.6 MBbls during 2003. The Canadian properties which were sold in January 2003 contributed 27.7

MBbls of crude oil production in 2002 compared to 2.4 MBbls in 2003 through the date of the sale. Crude oil production volumes relating to the Canadian properties which were retained and current drilling activities in Canada resulted in an increase to 29.0 MBbls in 2003 compared to 9.5 MBbls in 2002. Crude oil production from U.S. operations decreased due primarily to natural field declines. Natural gas sales volumes decreased from 15.5 Bcf in 2002 to 6.2 Bcf in 2003. This decrease is primarily due to the sale of our Canadian subsidiaries in January 2003. The Canadian properties sold contributed 9.8 Bcf in 2002 compared to .558 MMcf in 2003 through the date of sale.

Average sales prices in 2003 net of hedging costs were:

- $30.32 per Bbl of crude oil,
- $24.47 per Bbl of natural gas liquids, and
- $ 4.78 per Mcf of natural gas.

Average sales prices in 2002 net of hedging costs were:

- $24.34 per Bbl of crude oil,
- $17.94 per Bbl of natural gas liquids, and
- $ 2.55 per Mcf of natural gas.

Lease Operating Expense. Lease operating expense, or LOE, decreased from $15.2 million in 2002 to $9.6 million in 2003 The decrease in LOE is primarily due the sale of Canadian Abraxas and Old Grey Wolf in January 2003. LOE related to the properties owned by Canadian Abraxas and Old Grey Wolf was $7.3 million for the year ended December 31, 2002. Excluding the properties sold, LOE attributable to on going operations increased, primarily due to higher production taxes associated with higher commodity prices in 2003 as compared to 2002. Our LOE on a per Mcfe basis for the year ended December 31, 2003 was $1.21 per Mcfe compared to $0.82 for 2002, primarily due to the decrease in production volumes.

G&A Expense. General and administrative, or G&A, expense decreased from $6.9 million in 2002 to $5.4 million in 2003 The decrease in G&A expense was primarily due to a reduction in personnel in connection with the sale of Canadian Abraxas and Old Grey Wolf on January 23, 2003. Our G&A expense on a per Mcfe basis increased from $0.37 in 2002 to $0.67 in 2003. The increase in the per Mcfe cost was due primarily to lower production volumes in 2003 as compared to 2002.

G&A - Stock-based Compensation Expense. Effective July 1, 2000, the Financial Accounting Standards Board ("FASB") issued FIN 44, "Accounting for Certain Transactions Involving Stock Compensation", an interpretation of Accounting Principles Board Opinion No. ("APB") 25. Under the interpretation, certain modifications to fixed stock option awards which were made subsequent to December 15, 1998, and not exercised prior to July 1, 2000, require that the awards be subject to variable accounting until they are exercised, forfeited, or expired. In March 1999, we amended the exercise price to $2.06 on all options with an existing exercise price greater than $2.06. In January 2003, we amended the exercise price to $0.66 per share on certain options with an existing exercise price greater than $0.66 per share which resulted in variable accounting. We charged approximately $1.1 million to stock based compensation expense in 2003 related to these repricings. During 2002, we did not recognize any stock-based compensation due to the decline in the price of our common stock.

DD&A Expense. Depreciation, depletion and amortization, or DD&A, expense decreased by $15.7 million from $26.5 million in 2002 to $10.8 million in 2003. The decrease in DD&A was primarily due to the sale of our Canadian subsidiaries in January 2003 as well as ceiling limitation write-downs in the second quarter of 2002. Our DD&A expense on a per Mcfe basis for 2003 was $1.33 per Mcfe as compared to $1.42 per Mcfe in 2002.

Interest Expense. Interest expense decreased from $34.1 million to $17.0 million for 2003 compared to 2002. The decrease in interest expense was due to the reduction in debt in 2003. Total debt was reduced as a result of the transactions which occurred on January 23, 2003. Total debt was $300.4 million as of December 31, 2002 compared to $184.6 million at December 31, 2003.

Ceiling Limitation Write-down. We record the carrying value of our crude oil and natural gas properties using the full cost method of accounting. For more information on the full cost method of accounting, you should read the description under "Critical Accounting Policies-- Full Cost Method of Accounting for Crude Oil and Natural Gas Activities". At June 30, 2002, our net capitalized costs of crude oil and natural gas properties exceeded the present value of our estimated proved reserves by $138.7 million ($28.2 million on the U.S. properties and $110.5 million on the Canadian properties). These amounts were calculated considering June 30, 2002 prices of $26.12 per Bbl for crude oil and $2.16 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. Subsequent to June 30, 2002, commodity prices increased in Canada and we utilized these increased prices in calculating the ceiling limitation write-down. The total write-down was approximately $116.0 million. At December 31, 2003 our net capitalized cost of crude oil and natural gas properties did not exceed the present value of our estimated reserves, due to increased commodity prices during 2003 and, as such, no write-down was recorded in 2003. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future.

The risk that we will be required to write-down the carrying value of our crude oil and natural gas assets increases when crude oil and natural gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves or if purchasers or governmental action cause an abrogation of, or if we voluntarily cancel, long-term contracts for our natural gas. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved resources are revised downward, a further write-down of the carrying value of our crude oil and natural gas properties may be required.

Income taxes. Income tax expense increased from a benefit of $29.7 million for the year ended December 31, 2002 to an expense of $377,000 for the year ended December 31, 2003. The expense in 2003 was related to the operations of the Canadian properties prior to their sale on January 23, 2003. There is no current or deferred income tax expense for 2003 related to on-going operations due to the valuation allowance which has been recorded against the deferred tax asset.

Comparison of Year Ended December 31, 2002 to Year Ended December 31, 2001.

Operating Revenue. During the year ended December 31, 2002, operating revenue from crude oil, natural gas and natural gas liquids sales decreased by $22.3 million from $73.2 million in 2001 to $50.9 million in 2002. This decrease was primarily attributable to a decrease in production volumes and lower commodity prices in 2002 as compared to 2001. Crude oil and natural gas revenue was impacted by $11.5 million from a decline in commodity prices and $10.8 million from reduced production. The decline in production was due to the disposition of certain properties in south Texas and natural field declines.

Natural gas liquids volumes declined from 278.0 MBbls in 2001 to 242.0 MBbls in 2002. Crude oil sales volumes declined from 454.1 MBbls in 2001 to

292.3 MBbls during 2002. Natural gas sales volumes decreased from 17.5 Bcf in 2001 to 15.5 Bcf in 2002. Production declines were primarily attributable to our disposition of assets during 2002 and natural field declines.

Average sales prices in 2002 net of hedging losses were:

- $ 24.34 per Bbl of crude oil,

- $ 17.94 per Bbl of natural gas liquids, and
- $ 2.55 per Mcf of natural gas.

Average sales prices in 2001 net of hedging losses were:

- $24.63 per Bbl of crude oil,
- $21.51 per Bbl of natural gas liquids, and
- $ 3.20 per Mcf of natural gas.

Lease Operating Expense. LOE expense decreased from $18.6 million in 2001 to $15.2 million in 2002. LOE on a per Mcfe basis for 2002 was $0.82 per Mcfe as compared to $0.83 per Mcfe in 2001. The decrease in the per Mcfe cost is due to a reduced operating cost offset by the decline in production volumes.

G&A Expense. G&A expense increased slightly from $6.4 million in 2001 to $6.9 million in 2002. This increase was due primarily to increased legal expenses related to ongoing litigation in 2002. Our G&A expense on a per Mcfe basis increased from $0.30 in 2001 to $0.37 in 2002. The increase in the per Mcfe cost was due primarily to lower production volumes in 2002 as compared to 2001.

G&A - Stock-based Compensation Expense. Effective July 1, 2000, the Financial Accounting Standards Board ("FASB") issued FIN 44, "Accounting for Certain Transactions Involving Stock Compensation", an interpretation of Accounting Principles Board Opinion No. ("APB") 25. Under the interpretation, certain modifications to fixed stock option awards which were made subsequent to December 15, 1998, and not exercised prior to July 1, 2000, require that the awards be subject to variable accounting until they are exercised, forfeited, or expired. In March 1999, we amended the exercise price to $2.06 on all options with an existing exercise price greater than $2.06. We charged approximately $2.8 million to stock-based compensation expense in 2000 compared to crediting approximately $2.8 million in 2001. This was due to the decline in the market price of our Common stock during 2001. During 2002, we did not recognize any stock-based compensation due to the decline in the price of our common stock.

DD&A Expense. DD&A expense decreased by $5.9 million from $32.4 million in 2001 to $26.5 million in 2002. The decline in DD&A is due to reductions in our full cost pool resulting from ceiling test write-downs, as well as lower production volumes. Our DD&A expense on a per Mcfe basis for 2002 was $1.42 per Mcfe as compared to $1.74 per Mcfe in 2001.

Interest Expense. Interest expense increased from $31.5 million to $34.1 million for 2002 compared to 2001. The increase was the result of additional sales pursuant to our production payment arrangement with Mirant Americas as well as increased borrowings under Old Grey Wolf's credit facility in 2002. The production payment was reacquired in June 2002 for approximately $6.8 million.

Ceiling Limitation Write-down. We record the carrying value of our crude oil and natural gas properties using the full cost method of accounting. For more information on the full cost method of accounting, you should read the description under "Critical Accounting Policies-- Full Cost Method of Accounting for Crude Oil and Natural Gas Activities". As of December 31, 2001, the Company's net capitalized costs of crude oil and natural gas properties exceeded the present value of its estimated proved reserves by $71.3 million. These amounts were calculated considering 2001 year-end prices of $19.84 per Bbl for crude oil and $2.57 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. The Company did not adjust its capitalized costs for its U.S. properties because subsequent to December 31, 2001, crude oil and natural gas prices increased such that capitalized costs for its U.S. properties did not exceed the present value of the estimated proved crude oil and natural gas reserves for its U.S. properties as determined using increased realized prices on March 22, 2002 of $24.16 per Bbl for crude oil and $2.89 per Mcf for natural gas.

At June 30, 2002, our net capitalized costs of crude oil and natural gas properties exceeded the present value of our estimated proved reserves by $138.7 million ($28.2 million on the U.S. properties and $110.5 million on the Canadian properties). These amounts were calculated considering June 30, 2002 prices of $26.12 per Bbl for crude oil and $2.16 per Mcf for natural gas as adjusted to reflect the expected realized prices for each of the full cost pools. Subsequent to June 30, 2002, commodity prices increased in Canada and we utilized these increased prices in calculating the ceiling limitation write-down. The total

write-down was approximately $116.0 million. At December 31, 2002, our net capitalized cost of crude oil and natural gas properties did not exceed the present value of our estimated reserves, due to increased commodity prices during the fourth quarter and, as such, no further write-down was recorded. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future.

The risk that we will be required to write-down the carrying value of our crude oil and natural gas assets increases when crude oil and natural gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves or if purchasers or governmental action cause an abrogation of, or if we voluntarily cancel, long-term contracts for our natural gas. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved resources are revised downward, a further write-down of the carrying value of our crude oil and natural gas properties may be required.

Income taxes. Income tax expense decreased from an expense of $2.4 million for the year ended December 31, 2001 to a benefit of $29.7 million for the year ended December 31, 2002. The decrease was primarily due to the tax benefit relating to the ceiling limitation write-down related to our Canadian properties.

Liquidity and Capital Resources

General. The crude oil and natural gas industry is a highly capital intensive and cyclical business. Our capital requirements are driven principally by our obligations to service debt and to fund the following costs: o the development of existing properties, including drilling and completion costs of wells;

o acquisition of interests in crude oil and natural gas properties; and

o production and transportation facilities.

The amount of capital available to us will affect our ability to service our existing debt obligations and to continue to grow the business through the development of existing properties and the acquisition of new properties.

Our sources of capital are primarily cash on hand, cash from operating activities, funding under the senior credit agreement and the sale of properties. Our overall liquidity depends heavily on the prevailing prices of crude oil and natural gas and our production volumes of crude oil and natural gas. Significant downturns in commodity prices, such as that experienced in the last nine months of 2001 and the first quarter of 2002, can reduce our cash from operating activities. Although we have hedged a portion of our natural gas and crude oil production and will continue this practice as required pursuant to the senior credit agreement, future crude oil and natural gas price declines would have a material adverse effect on our overall results, and therefore, our liquidity. Low crude oil and natural gas prices could also negatively affect our ability to raise capital on terms favorable to us and could also reduce the borrowing base under our senior credit agreement.

If the volume of crude oil and natural gas we produce decreases, our cash flow from operations will decrease. Our production volumes will decline as reserves are produced. In addition, due to sales of properties in 2002 and January 2003, we now have reduced reserves and production levels. In the future, we may sell additional properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration, exploitation and development activities, acquire additional producing properties or identify additional behind-pipe zones or secondary recovery reserves. While we have had some success in pursuing these activities, historically, we have not been able to fully replace the production volumes lost from natural field declines and property sales.

Working Capital. At December 31, 2003, our current liabilities of approximately $12.6 million exceeded our current assets of $10.2 million resulting in a working capital deficit of $2.4 million. This compares to a working capital deficit of $65.7 million as of December 31, 2002. Current liabilities as of December 31, 2003 consisted of trade payables of $6.8 million, revenues due third parties $2.3 million, accrued interest related to our New Notes of $2.3 million, of which $2.0 is non-cash and other accrued liabilities of $ 1.2 million. We do not expect to make cash interest payments with respect

to the outstanding New Notes, and the issuance of additional New Notes in lieu of cash interest payments thereon will not affect our working capital balance.

Capital Expenditures. Capital expenditures in 2001, 2002 and 2003 were $57.1 million, $38.7 million and $18.3 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2003.

	Year Ended December 31,		
	2001	2002	2003
	(dollars in thousands)		
Expenditure category:			
Development	$ 56,694	$ 38,560	$ 18,313
Facilities and other	362	154	36
Total	$ 57,056	$ 38,714	$ 18,349

During 2001, 2002 and 2003, capital expenditures were primarily for the development of existing properties. We currently have a capital expenditure budget of $10 million for 2004, of which $5.0 million is allocated to U.S. projects and $5.0 million is allocated to Canadian drilling projects. We plan to participate in the drilling or putting on production of 17 gross (13 net) wells, of which 11 gross (11 net) wells will be operated by us. Our capital expenditures could also include expenditures for acquisition of producing properties if such opportunities arise, but we currently have no agreements, arrangements or undertakings regarding any material acquisitions. We have no material long-term capital commitments and are consequently able to adjust the level of our expenditures as circumstances dictate. Additionally, the level of capital expenditures will vary during future periods depending on market conditions and other related economic factors. Should the prices of crude oil and natural gas decline from current levels, our cash flows will decrease which may result in a reduction of the capital expenditures budget. If we decrease our capital expenditures budget, we may not be able to offset crude oil and natural gas production volumes decreases caused by natural field declines and sales of producing properties.

Sources of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	2001	2002
	(dollars in thousands)	
Net cash (used in) provided by operating activities	$ 16,263	$ (8,336)
Net cash (used in) provided by investing activities	(30,797)	(5,036)
Net cash provided by (used in) financing activities	20,685	10,836
Total	$ 6,151	$ (2,536)

Operating activities for the year ended December 31, 2003 provided us with $23.9 million of cash. Investing activities provided us $67.5 million during 2003. Financing activities used $95.6 million during 2003. Most of these funds were used to reduce our long-term debt and were generated by the sale of our Canadian subsidiaries and the exchange offer completed in January 2003. The sale of our Canadian subsidiaries contributed $85.8 million in 2003 reduced by $18.3 million in exploration and development expenditures. Expenditures in 2003 were primarily for the development of crude oil and natural gas properties.

Operating activities for the year ended December 31, 2002 used $8.4 million of cash. Investing activities used $5.0 million during 2002. Our investing activities included the sale of properties which provided $33.9 million, and the use of $38.9 million primarily for the development of producing properties. Financing activities provided us with $10.8 million during 2002, relating primarily to advances on Old Grey Wolf's credit facility.

Operating activities for the year ended December 31, 2001 provided us $16.3 million of cash. Investing activities included the sale of properties which provided $28.9 million, and the use of $57.1 million for the development of producing properties and $2.7 million for the acquisition of the minority interest in Grey Wolf. Financing activities provided $20.7 million during 2001, including the provision of additional funding of $11.7 million under our production payment arrangement with Mirant Americas, and the provision of $18.3 million under Old Grey Wolf's credit facility. Payments on long-term debt used $9.3 million.

Future Capital Resources. We will have four principal sources of liquidity going forward: (i) cash on hand, (ii) cash from operating activities, (iii) funding under the senior credit agreement, and (iv) sales of producing properties. Covenants under the indenture for the New Notes and the senior credit agreement restrict our use of cash on hand, cash from operating activities and any proceeds from asset sales. We may also attempt to raise additional capital through the issuance of additional debt or equity securities, although the terms of the new note indenture and the senior credit agreement substantially restrict our ability to:

- incur additional indebtedness;
- incur liens;
- pay dividends or make certain other restricted payments;
- consummate certain asset sales;
- enter into certain transactions with affiliates;
- merge or consolidate with any other person; or
- sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of our assets.

Contractual Obligations

We are committed to making cash payments in the future on the following types of agreements:

- Long-term debt
- Operating leases for office facilities

We have no off-balance sheet debt or unrecorded obligations and we have not guaranteed the debt of any other party. Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2003.

Contractual Obligations (dollars in thousands)	Payments due in:				
	Total	Less than one year	1-3 years	3-5 years	More tha years
Long-Term Debt (1)	$ 241,399	$ -	$ 57,155	$ 184,244	$
Operating Leases (2)	1,373	416	796	161	

(1) These amounts represent the balances outstanding under the senior credit agreement and the New Notes. These repayments assume that interest will be capitalized under the New Notes and that periodic interest on the senior credit agreement will be paid on a monthly basis and that we will not draw down additional funds thereunder.

(2) These amounts represent office lease obligations. Leases for office space for Abraxas and New Grey Wolf expire in April 2006 and December 2008, respectively.

Other obligations. We make and will continue to make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of crude oil and natural gas. In the past, we have funded our operations and capital expenditures primarily through cash flow from operations, sales of properties, sales of production payments and borrowings under our bank credit facilities and other sources. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion.

Long-Term Indebtedness. The financial restructuring completed in January 2003 resulted in the retirement of our first lien notes, second lien notes and old notes, together with the Old Grey Wolf credit facility. The following table sets forth our long-term indebtedness as of December 31, 2002, and 2003.

Long Term Indebtedness

	December 31	
	2002	2003
	(in thousands)	
11.5% Senior Notes due 2004 ("Old Notes")	$ 801	$
12.875% Senior Secured Notes due 2003 ("First Lien Notes")	63,500	
11.5% Second Lien Notes due 2004 ("Second Lien Notes")	190,178	
9.5% Senior Credit Facility ("Grey Wolf Facility") providing for borrowings up to approximately US $96 million (CDN $150 million). Secured by the assets of Old Grey Wolf and non-recourse to Abraxas	45,964	
11.5% Secured Notes due 2007 ("New Notes")	-	137,2
Senior Credit Agreement	-	47,3
	300,443	184,6
Less current maturities	63,500	
	$ 236,943	$ 184,6

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(1) At March 9, 2004, the outstanding principal balance on our senior credit agreement was $50.7 million.

For financial reporting purposes, the New Notes are reflected at the carrying value of the Second Lien Notes and Old Notes prior to the exchange of $191.0 million, net of the cash offered in the exchange of $47.5 million and net of the fair market value related to equity of $3.8 million offered in the exchange transaction. The face amount of the New Notes was $120.5 million at December 31, 2003 including $10.8 million in new notes issued for interest.

The New Notes accrue interest from the date of issuance, at a fixed annual rate of 11 1/2%, payable in cash semi-annually on each May 1 and November 1, commencing May 1, 2003. We will pay such unpaid interest in kind by the issuance of additional New Notes with a principal amount equal to the amount of accrued and unpaid cash interest on the New Notes plus an additional 1% accrued interest for the applicable period. Upon an event of default, the New Notes accrue interest at an annual rate of 16.5%.

The New Notes are secured by a second lien or charge on all of our current and future assets, including, but not limited to, all of our crude oil and natural gas properties. All of Abraxas' current subsidiaries, Sandia Oil & Gas, Sandia Operating (a wholly-owned subsidiary of Sandia Oil & Gas), Wamsutter, New Grey Wolf, Western Associated Energy and Eastside Coal, are guarantors of the New Notes, and all of Abraxas' future subsidiaries will guarantee the New Notes. If Abraxas cannot make payments on the New Notes when they are due, the guarantors must make them instead.

The New Notes and related guarantees

- are subordinated to the indebtedness under the new senior secured credit agreement;

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- rank equally with all of Abraxas' current and future senior indebtedness; and
- rank senior to all of Abraxas' current and future subordinated indebtedness, in each case, if any.

The New Notes are subordinated to amounts outstanding under the new senior secured credit agreement both in right of payment and with respect to lien priority and are subject to an intercreditor agreement.

Abraxas may redeem the New Notes, at its option, in whole at any time or in part from time to time, at redemption prices expressed as percentages of the principal amount set forth below. If Abraxas redeems all or any New Notes, it must also pay all interest accrued and unpaid to the applicable redemption date. The redemption prices for the New Notes during the indicated time periods are as follows:

Period	Percentage
From January 24, 2004 to June 23, 2004	97.1674%
From June 24, 2004 to January 23, 2005	98.5837%
Thereafter	100.0000%

Under the indenture, we are subject to customary covenants which, among other things, restrict our ability to:

- borrow money or issue preferred stock;
- pay dividends on stock or purchase stock;
- make other asset transfers;
- transact business with affiliates;
- sell stock of subsidiaries;
- engage in any new line of business;
- impair the security interest in any collateral for the notes;

- use assets as security in other transactions; and

- sell certain assets or merge with or into other companies.

In addition, we are subject to certain financial covenants including covenants limiting our selling, general and administrative expenses and capital expenditures, a covenant requiring Abraxas to maintain a specified ratio of consolidated EBITDA, as defined in the agreements, to cash interest and a covenant requiring Abraxas to permanently, to the extent permitted, pay down debt under the new senior secured credit agreement and, to the extent permitted by the new senior secured credit agreement, the New Notes or, if not permitted, paying indebtedness under the new senior secured credit agreement.

The indenture contains customary events of default, including nonpayment of principal or interest, violations of covenants, inaccuracy of representations or warranties in any material respect, cross default and cross acceleration to certain other indebtedness, bankruptcy, material judgments and liabilities, change of control and any material adverse change in our financial condition.

Senior Credit Agreement. In connection with the financial restructuring, Abraxas entered into a new senior credit agreement providing a term loan facility and a revolving credit facility as described below. Subsequently, on February 23, 2004, Abraxas entered into an amendment to its existing senior credit agreement providing for two revolving credit facilities and a new non-revolving credit facility as described below. Subject to earlier termination on the occurrence of events of default or other events, the stated maturity date for these credit facilities is February 1, 2007. In the event of an early termination, we will be required to pay a prepayment premium, except in the limited circumstances described in the amended senior credit agreement.

First Revolving Credit Facility. Lenders under the amended senior credit agreement have provided a revolving credit facility to Abraxas with a maximum borrowing base of up to $20 million. Our current borrowing base under this revolving credit facility is the full $20.0 million, subject to adjustments based on periodic calculations and mandatory prepayments under the senior credit agreement. We have borrowed $6.6 million under this revolving credit facility, which was used to refinance principal and interest on advances under our preexisting revolving credit facility under the senior credit agreement, and to pay certain fees and expenses relating to the transaction. Outstanding amounts under this revolving credit facility bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 1.125%.

Second Revolving Credit Facility. Lenders under the amended senior credit agreement have provided a second revolving credit facility to Abraxas, with a maximum borrowing of up to $30 million. This revolving credit facility is not subject to a borrowing base. We have borrowed $30.0 million under this revolving credit facility, which was used to refinance principal and interest on advances under our preexisting revolving credit facility, and to pay certain transaction fees and expenses. Outstanding amounts under this revolving credit facility bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 3.00%.

Non-Revolving Credit Facility. Abraxas has borrowed $15.0 million pursuant to a non-revolving credit facility, which was used to repay the preexisting term loan under our senior credit agreement, to refinance principal and interest on advances under the preexisting revolving credit facility, and to pay certain transaction fees and expenses. This non-revolving credit facility is not subject to a borrowing base. Outstanding amounts under this credit facility bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 8.00%.

Covenants. Under the amended senior credit agreement, Abraxas is subject to customary covenants and reporting requirements. Certain financial covenants require Abraxas to maintain minimum ratios of consolidated EBITDA (as defined in the amended senior credit agreement) to adjusted fixed charges (which includes certain capital expenditures), minimum ratios of consolidated EBITDA to cash interest expense, a minimum level of unrestricted cash and revolving credit availability, minimum hydrocarbon production volumes and minimum proved developed hydrocarbon reserves. In addition, if on the day before the end of each fiscal quarter the aggregate amount of our cash and cash equivalents exceeds $2.0 million, we are required to repay the loans under the amended senior credit agreement in an amount equal to such excess. The amended senior credit agreement also requires us to enter into hedging agreements on not less than 40% or more than 75% of our projected oil and gas production. We are also required to establish deposit accounts at financial institutions acceptable to the lenders and we are required to direct our customers to make all payments into these accounts. The amounts in these accounts will be transferred to the lenders upon the occurrence and during the continuance of an event of default under the amended senior credit agreement.

In addition to the foregoing and other customary covenants, the amended senior credit agreement contains a number of covenants that, among other things, restrict our ability to:

- incur additional indebtedness;
- create or permit to be created liens on any of our properties;
- enter into change of control transactions;
- dispose of our assets;
- change our name or the nature of our business;
- make guarantees with respect to the obligations of third parties;
- enter into forward sales contracts;
- make payments in connection with distributions, dividends or redemptions relating to our outstanding securities, or
- make investments or incur liabilities.

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Security. The obligations of Abraxas under the amended senior credit agreement continue to be secured by a first lien security interest in substantially all of Abraxas' assets, including all crude oil and natural gas properties.

Guarantees. The obligations of Abraxas under the amended senior credit agreement continue to be guaranteed by Abraxas' subsidiaries, Sandia Oil & Gas, Sandia Operating, Wamsutter, New Grey Wolf, Western Associated Energy and Eastside Coal. The guarantees under the amended senior credit agreement continue to be secured by a first lien security interest in substantially all of the guarantors' assets, including all crude oil and natural gas properties.

Events of Default. The amended senior credit agreement contains customary events of default, including nonpayment of principal or interest, violations of covenants, inaccuracy of representations or warranties in any material respect, cross default and cross acceleration to certain other indebtedness, bankruptcy, material judgments and liabilities, change of control and any material adverse change in our financial condition.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. Under the senior credit agreement, we are required to maintain hedge positions on not less than 40% or more than 75% of our projected oil and gas production for a six month rolling period. See "Quantitative and Qualitative Disclosures about Market Risk--Hedging Sensitivity" for further information.

Net Operating Loss Carryforwards

At December 31, 2003, the Company had, subject to the limitation discussed below, $100.6 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2022 if not utilized. In connection with January 2003 transactions described in Note 2, in Notes to Consolidated Financial Statements, certain of the loss carryforwards were utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, the Company has established a valuation allowance of $99.1 million and $76.1 million for deferred tax assets at December 31, 2002 and 2003, respectively.

Related Party Transactions

Accounts receivable - Other includes approximately $51,211 and $35,558 as of December 31, 2002 and 2003, respectively, representing amounts due from officers relating to advances made to employees.

On July 29, 2003 Abraxas acquired all of the shares of the capital stock of Wind River Resources Corporation which owned an airplane. The sole shareholder of Wind River was the Company's President. The consideration for the purchase was 106,977 shares of Abraxas common stock and $35,000 in cash. Simultaneously with this transaction, the airplane was sold. The airplane had previously been made available to Abraxas employees for business use.

The Company paid Wind River a total of approximately $314,000, $345,000 and $132,000 in 2001, 2002 and 2003, through July 29, 2003 respectively, for Wind River's operating cost associated with the Company's use of the plane.

Critical Accounting Policies

The preparation of financial statements in conformity with generally accepted accounting principles requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following represents those policies that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

Full Cost Method of Accounting for Crude Oil and Natural Gas Activities. SEC Regulation S-X defines the financial accounting and reporting standards for companies engaged in crude oil and natural gas activities. Two methods are prescribed: the successful efforts method and the full cost method. Abraxas has chosen to follow the full cost method under which all costs associated with property acquisition, exploration and development are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of crude oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of crude oil and natural gas properties under the successful efforts method. As a result our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization rate on our crude oil and natural gas properties.

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. The Company has experienced this situation several times over the years, most recently in 2002. Our crude oil and natural gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from the full cost method of accounting.

Under full cost accounting rules, the net capitalized cost of crude oil and natural gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of crude oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are depressed or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or if purchasers cancel long-term contracts for our natural gas production. An expense recorded in one period may not be reversed in a subsequent period even though higher crude oil and natural gas prices may have increased the ceiling applicable to the subsequent period.

For the year ended December 31, 2002, we recorded a write-down of approximately $116.0 million. The write-down in 2002 was due to low commodity prices. We cannot assure you that we will not experience additional write-downs in the future.

Estimates of our proved reserves included in this document are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions;
- and the judgment of the persons preparing the estimate.

The Company's proved reserve information included in this document was based on evaluations prepared by independent petroleum engineers. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, the Company based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

The estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which the Company records DD&A expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields.

Use of Estimates. The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Management believes that it is reasonably possible that estimates of proved crude oil and natural gas revenues could significantly change in the future.

Revenue Recognition. The Company recognizes crude oil and natural gas revenue from its interest in producing wells as crude oil and natural gas is sold from those wells, net of royalties. Revenue from the processing of natural gas is recognized in the period the service is performed. The Company utilizes the sales method to account for gas production volume imbalances. Under this method, income is recorded based on the Company's net revenue interest in production taken for delivery. The Company had no material gas imbalances.

Asset Retirement Obligations The estimated costs of restoration and removal of facilities are accrued. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense.

Hedge Accounting. From time to time, we use commodity price hedges to limit our exposure to fluctuations in crude oil and natural gas prices. Results of those hedging transactions are reflected in crude oil and natural gas sales.

Statement of Financial Accounting Standards, ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," was effective for the Company on January 1, 2001. SFAS 133, as amended and interpreted, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. Under this statement, all derivatives, whether designated in hedging relationships or not, are required to be recorded at fair value on our balance sheet. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results of the hedged item in the consolidated statement of operations. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. For derivative instruments designated as fair value hedges, changes in fair value, to the extent the hedge is effective, are recognized as an increase or decrease to the value of the hedged item until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in the fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings. Changes in fair value of contracts that do not meet the SFAS 133 definition of a cash flow or fair value hedge are also recognized in earnings through risk management income. All amounts initially recorded in this caption are ultimately reversed within the same caption and included in oil and gas sales or interest expense, as applicable, over the respective contract terms.

One of the primary factors that can have an impact on our results of operations is the method used to value our derivatives. We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently evaluated internally using established index prices and other sources. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Another factor that can impact our results of operations each period is our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated because energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of crude oil and natural gas prices and, to a lesser extent, interest rates, our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2003 the net market value of our derivatives was an asset of $21,136. As of December 31, 2002 we did not have any outstanding derivatives.

New Accounting Pronouncements

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights held under lease or other contractual arrangement associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of such mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights held under lease or other contractual arrangement associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify approximately $3.1 million and $4.2 million at December 31, 2002 and December 31, 2003, respectively, out of oil and gas properties and into a separate intangible assets line item. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full-cost accounting rules.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS 143 is effective for us January 1, 2003. SFAS 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense in the accompanying consolidated financial statements.

The Company adopted SFAS 143 effective January 1, 2003. For the year ended December 31, 2003 the Company recorded a charge of $395,341 for the cumulative effect of the change in accounting principal and a liability of $1.3 million. During 2003, the Company charged approximately $379,000 to expense related to the accretion of the liability. The impact on each of the prior periods was not material.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS 144). Effective January 1, 2002, the Company adopted SFAS 144. SFAS 144 retains the requirement to recognize an impairment loss only where the carrying value of a long-lived asset is not recoverable from its undiscounted cash flows and to measure such loss as the difference between the carrying amount and fair value of the asset. SFAS 144, among other things, changes the criteria that have to be met to classify an asset as held-for-sale and requires that operating losses from discontinued operations be recognized in the period that the losses are incurred rather than

as of the measurement date. This new standard had no impact on the Company's consolidated financial statements for the year ended December 31, 2003.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS 146). SFAS 146 requires costs associated with exit of disposal activities to be recognized when they are incurred rather than at the date of commitment to an exit or disposal plan. The Company is currently evaluating the impact the standard will have on its results of operations and financial condition. The official effective date of this standard has not been determined by the FASB.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on

Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149, among other things, clarifies the circumstances under which a contract with an initial net investment meets the characteristic of a derivative and amends the definition of an "underlying" to conform it to language used in FIN 45. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. The Company adopted this statement effective July 1, 2003. Implementation of this new standard did not have an effect on the Company's consolidated financial position or results of operations.

In November 2002 the FASB issued FASB Interpretation No. 45 (FIN 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN 45 elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees that it has issued, including loan guarantees such as standby letters of credit. It also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligations it has undertaken in issuing the guarantee. The Interpretation does not specify the subsequent measurement of the guarantor's recognized liability over the term of the related guarantee. The guidance in FIN 45 does not apply to certain guarantee contracts, such as those issued by insurance companies or for a lessee's residual value guarantee embedded in a capital lease. The provisions related to recognizing a liability at inception of the guarantee for the fair value of the guarantor's obligations would not apply to product warranties or to guarantees accounted for as derivatives. The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002, regardless of the guarantor's fiscal year-end. FIN 45 specifies additional disclosures effective for financial statements of interim or annual periods ending after December 15, 2002.

In January 2003 the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable-Interest Entities ("VIEs".) FIN 46 establishes the definition of VIEs to encompass a broader group of entities than those previously considered special-purpose entities (SPEs). FIN 46 specifies the criteria under which it is appropriate for an investor to consolidate VIEs; in order for an investor to consolidate a VIE, the entity must fall within the definition of VIE and the investor must fall within the definition of primary beneficiary, both newly defined terms under this FIN. The revised effective date of FIN 46 for public companies with VIEs meeting certain conditions, will be the end of the first interim or annual period ending after December 15, 2003. In December 2003, the FASB issued FASB Interpretation no. 46(R)m which expanded and clarified the guidelines of FIN 46.

In May 2003, the FASB issued FAS No. 150, entitled "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). This statement is effective for financial instruments entered into or modified after May 31, 2003, and is otherwise effective at the beginning of the first interim period beginning after June 15, 2003. The Company has no financial instruments affected by SFAS 150, therefore adoption by the Company as of July 1, 2003 will not impact the Company's financial statements.

Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent crude oil and natural gas producer, our revenue, cash flow from operations, other income and equity earnings and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of crude oil, natural gas and natural gas liquids. Declines in commodity prices will materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of crude oil and natural gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global political and economic conditions. Historically, prices received for crude oil and natural gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the year ended December 31, 2003, a 10% decline in crude oil, natural gas and natural gas liquids prices would have reduced our operating revenue, cash flow and net income by approximately $3.8 million for the year.

Hedging Sensitivity

On January 1, 2001, we adopted SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138. Under SFAS 133, all derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge or cash flow hedge. If the derivative qualifies for cash flow hedge accounting, the gain or loss on the derivative is deferred in Other Comprehensive Income/Loss, a component of Stockholders' Equity, to the extent that the hedge is effective. As of December 31, 2003 the derivatives that we have in place are not designated as hedges. Accordingly, changes in the fair market value of the derivatives are recorded in current period oil and gas revenue.

If a derivative qualifies for hedge accounting, the relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument becomes ineffective. Gains and losses deferred in accumulated Other Comprehensive Income/Loss related to a cash flow hedge that becomes ineffective, remain unchanged until the related production is delivered. If we determine that it is probable that a hedged transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

Gains and losses on qualified hedging instruments related to accumulated Other Comprehensive Income and adjustments to carrying amounts on hedged production are included in natural gas or crude oil production revenue in the period that the related production is delivered. For derivatives not qualifying for hedge accounting, changes in the fair market value of the instrument are charged to income in the current period.

In 2001 and 2002, we experienced hedging losses of $12.1 million and $3.2 million, respectively. In October 2002, all of these hedge agreements expired. Under the expired hedge agreements, we made total payments to various counterparties in the amount of $35.1 million.

Under the terms of the senior secured credit agreement, we are required to maintain hedging positions with respect to not less than 40% nor more than 75% of our crude oil and natural gas production for a rolling six month period. As of December 31, 2003 the Company's hedge positions were as follows:

Time Period	Notional Quantities	Price
March 1, 2003 - February 29, 2004	5,000 MMBtu of natural gas production per day	Floor of $4.50
March 1, 2004 - April 30, 2004	2,000 MMBtu of natural gas production per day	Floor of $4.00
March 1, 2004 - April 30, 2004	500 Bbls of crude oil production per day	Floor of $22.00
May 2004	2,000 Mmbtu of natural gas production per day	Floor of $4.00
May 2004	500 Bbls of crude oil production per day	Floor of $22.00
June 2004	800 Bbls of crude oil production per day	Floor of $22.00
July 2004	2,000 Mmbtu of natural gas production per day	Floor of $4.00
July 2004	500 Bbls of crude oil production per day	Floor of $22.00

Subsequent to year-end we have entered into additional agreements similar to those scheduled above (floors) in volume amounts sufficient to reach the 40% threshold required by our senior credit agreement. The Company anticipates continuing to purchase similar floors in the future to satisfy our requirements under the senior credit agreement.

Interest rate risk

At December 31, 2003, as a result of the financial restructuring that occurred in January 2003, we had approximately $47.4 million in outstanding indebtedness under the new senior secured credit agreement, accruing interest at a rate of prime plus 4.5%, subject to a minimum interest rate of 9.0%. In the event that the prime rate (currently 4.0%) rises above 4.5% the interest rate applicable to our outstanding indebtedness under the new senior secured credit agreement will rise accordingly. For every percentage point that the prime rate rises above 4.5%, our interest expense would increase by approximately $430,000 on an annual basis. Our New Notes accrue interest at fixed rates and are accordingly not subject to fluctuations in market rates.

As discussed in "Business - General" the senior secured credit agreement was amended in February 2004. Our interest rate under the terms of the amended credit agreement is a floating rate, currently at approximately 7.5%, assuming all available amounts are borrowed.

Foreign Currency

Our Canadian operations are measured in the local currency of Canada. As a result, our financial results are affected by changes in foreign currency exchange rates or weak economic conditions in the foreign markets. Our ongoing Canadian operations reported a pre-tax income $218,000 for the year ended December 31, 2003. It is estimated that a 5% change in the value of the U.S. dollar to the Canadian dollar would have changed our net income by approximately $10,900. We do not maintain any derivative instruments to mitigate the exposure to translation risk. However, this does not preclude the adoption of specific hedging strategies in the future.

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Financial Statements

Grey Wolf Exploration Inc.

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Abraxas Petroleum Corporation

We have audited the accompanying consolidated balance sheet of Abraxas Petroleum Corporation (the "Company") as of December 31, 2003, and the related consolidated statements of operations, stockholders' deficit, and cash flows and other comprehensive income for the year ended December 31, 2003. 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 audit 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 audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Abraxas Petroleum Corporation at December 31, 2003, and the results of its operations and its cash flows for the year ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, as of January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

/s/BDO Seidman, LLP
Dallas, Texas
February 13, 2004

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of
Abraxas Petroleum Corporation

We have audited the accompanying consolidated balance sheet of Abraxas Petroleum Corporation and Subsidiaries (the "Company") as of December 31, 2002, and the related consolidated statements of operations, stockholders' deficit, and cash flows and other comprehensive income for each of the two years in the 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, such consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2002, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, on January 23, 2003, the Company sold all of the outstanding common stock of two wholly owned subsidiaries, Canadian Abraxas Petroleum Limited and Grey Wolf Exploration, Inc., repaid certain debt, and also entered into an agreement to exchange cash, new debt and common stock of the Company for certain other debt.

As discussed in Note 19 to the financial statements, the accompanying 2001 and 2002 financial statements have been restated.

/s/DELOITTE & TOUCHE LLP
San Antonio, Texas
March 10, 2003 (July 18, 2003, as to Note 19 and the first paragraph of "New Accounting Pronouncements" in Note 1)

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31	
	2002	2003
	(Dollars in thousands)	
Current assets:		
Cash	$ 4,882	$
Accounts receivable:		
Joint owners	2,215	
Oil and gas production sales	7,466	
Other	364	
	10,045	
Equipment inventory	1,014	
Other current assets	1,240	
Total current assets	17,181	1

Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	521,995	32
Unproved, not subject to amortization	7,052	
Other property and equipment	44,189	
Total	573,236	33
Less accumulated depreciation, depletion, and amortization	422,842	22
Total property and equipment - net	150,394	11
Deferred financing fees net	5,671	
Deferred income taxes....................................	7,820	
Other assets	359	
Total assets	$ 181,425	$ 12

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' DEFICIT

	December 31	
	2002	2003
	(Dollars in thousands)	
Current liabilities:		
Accounts payable	$ 9,687	$
Joint interest oil and gas production payable	2,432	
Accrued interest	6,009	
Other accrued expenses	1,162	
Current maturities of long-term debt	63,500	
Total current liabilities................................	82,790	1
Long-term debt	236,943	18
Future site restoration	3,946	
Stockholders' equity (deficit):		
Common stock, par value $.01 per share - authorized 200,000,000 shares; issued 30,145,280 and 36,024,308 at December 31, 2002 and 2003 respectively...........	301	
Additional paid-in capital	136,830	14

Receivables from stock sale...............................	(97)	
Accumulated deficit	(269,621)	(21
Treasury stock, at cost, 165,883 shares..................	(964)	
Accumulated other comprehensive income (loss).............	(8,703)	
Total stockholders' deficit..................................	(142,254)	(7
Total liabilities and stockholders' deficit...............	$ 181,425	$ 12

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December	
	2001	2002
	(In thousands except per s	
Revenues:		
Oil and gas production revenues	$ 73,201	$ 50,862
Gas processing revenues..................................	2,438	2,420
Rig revenues	756	635
Other	848	403
	77,243	54,320
Operating costs and expenses:		
Lease operating and production taxes	18,616	15,240
Depreciation, depletion, and amortization	32,484	26,539
Proved property impairment	2,638	115,993
Rig operations	702	567
General and administrative	6,445	6,884
Stock-based compensation................................	(2,767)	-
	58,118	165,223
Operating income (loss)....................................	19,125	(110,903
Other (income) expense:		
Interest income	(78)	(92
Amortization of deferred financing fees	2,268	2,095
Interest expense	31,523	34,150
Financing costs..	-	967
Loss on sale of equity investment	845	-
Gain on sale of foreign subsidiaries....................	-	-
Other	207	201
	34,765	37,321
Income (loss) before cumulative effect of accounting change		

and taxes	(15,640)	(148,224
Income tax expense (benefit):		
Current	505	-
Deferred	1,897	(29,697
Minority interest in income of foreign subsidiary (2001 prior to purchase)	1,676	-
Cumulative effect of accounting change	-	-
Net income (loss)	$ (19,718)	$ (118,527
Basic earnings (loss)per common share:		
Net earnings (loss)	$ (0.76)	$ (3.95
Cumulative effect of accounting change	-	-
Net income (loss) per common share - basic	$ (0.76)	$ (3.95
Diluted earnings (loss) per common share:		
Net earnings (loss)	$ (0.76)	$ (3.95
Cumulative effect of accounting change	-	-
Net income (loss) per common share - diluted	$ (0.76)	$ (3.95)

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' DEFICIT
(In thousands except share amounts)

	Common Stock		Treasury Stock		Additional Paid-In Capital
	Shares	Amount	Shares	Amount	
Balance at December 31, 2000	22,759,852	$ 227	165,883	$ (964)	$ 130,409
Comprehensive income (loss)					
Net loss	--		--	--	--
Other comprehensive income:					
Hedge loss	--		--	--	--
Foreign currency translation adjustment. adjustment	--		--	--	--
Comprehensive income (loss)	(28,480)				
Stock-based compensation expense	--		--	--	(2,767)
Issuance of common stock					

for contingent value rights	3,383,488	34	--	--	(34)
Issuance of common stock and stock options for acquisition of minority interest in .... Old Grey Wolf Exploration, Inc.	3,990,565	40	--	--	9,206
Stock options exercised ...	8,375	--	--	16	--
Balance at December 31, 2001 .	30,145,280	$ 301	165,883	$ (964)	$ 136,830
Comprehensive income (loss):					
Net loss	--	--	--	--	--
Other comprehensive income:					
Hedge income	--	--	--	--	--
Foreign currency translation .... adjustment	--	--	--	--	--
Comprehensive income (loss)					
Balance at December 31, 2002..	30,145,280	$ 301	165,883	$ (964)	$ 136,830

	Accumuated Deficit	Accumulated Other Comprehensive Income (loss)	Recivables From Stock Sale	Total
Balance at December 31, 2000 .	$ (131,376)	$ (4,799)	$ (97)	$ (6,600)
Comprehensive income (loss):				
Net loss	(19,718)	--	--	(19,718)
Other comprehensive income:				
Hedge loss	--	(566)	--	(566)
Foreign currency translation adjustment. adjustment	--	(8,196)	--	(8,196)
Comprehensive income (loss)..				(24,480)
Stock-based compensation expense	--	--	--	(2,767)
Issuance of common stock for contingent value rights	--	--	--	--
Issuance of common stock and stock options for acquisition of minority interest in Old Grey Wolf Exploration, Inc.	--	--	--	9,246
Stock options exercised ...	--	--	--	16
Balance at December 31, 2001 .	$(151,094)	$ (13,561)	$ (97)	$ (28,585)

Comprehensive income (loss):				
Net loss	(118,527)	--	--	(118,527)
Other comprehensive income:				
Hedge income	--	566	--	566
Foreign currency translation .... adjustment	--	4,292	--	4,292
Comprehensive income (loss)				(113,669)
Balance at December 31, 2002. .	$ (269,621)	$ (8,703)	$ (97)	$ (142,254)

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' DEFICIT (continued)
(In thousands except share amounts)

	Common Stock		Treasury Stock		Additional Paid-In Capital
	Shares	Amount	Shares	Amount	
Balance at December 31, 2002..	30,145,280	$ 301	165,883	$ (964)	$136,830
Comprehensive income (loss):					
Net income	--	--	--	--	--
Other comprehensive income (loss):					
Foreign currency translation adjustment	--	--	--	--	--
Comprehensive income					
Stock-based compensation expense	--	--	--	--	1,106
Stock options exercised .	129,352	1	--	--	84
Stock issued for acquisition of Wind ... River Resources	106,977	1	--	--	91
Stock issued in connection with exchange offer	5,642,699	57	--	--	3,724
Balance at December 31, 2003.	36,024,308	$ 360	165,883	$ (964)	$ 141,835

	Accumuated Deficit	Accumulated Other Comprehensive Income (loss)	Recivables From Stock Sale	Total
Balance at December 31, 2002.	$ (269,621)	$ (8,703)	$ (97)	$ (142,254)
Comprehensive income (loss):				
Net income	55,920	--	--	55,920
Other comprehensive income (loss):				
Foreign currency translation adjustment	--	9,067	--	9,067
Comprehensive income				64,987
Stock-based compensation expense	--	--	--	1,106
Stock options exercised .	--	--	--	85
Stock issued for acquisition of Wind ... River Resources	--	--	--	92
Stock issued in connection with exchange offer.........	--	--	--	3,781
Balance at December 31, 2003	$ (213,701)	$ 364	$ (97)	$ (72,203)

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended	
	2001	2
	(In th	
Operating Activities		
Net income (loss)	$ (19,718)	$
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Minority interest in income of foreign subsidiary	1,676	
Loss on sale of equity investment................	845	
(Gain) on sale of foreign subsidiaries...........	-	
Depreciation, depletion, and amortization	32,484	
Non-cash interest and financing cost............	-	
Proved property impairment	2,638	

Deferred income tax expense (benefit)...........	1,897	
Amortization of deferred financing fees.........	2,268	
Stock-based compensation	(2,767)	
Changes in operating assets and liabilities:		
Accounts receivable	12,693	
Equipment inventory	(76)	
Other	(106)	
Accounts payable	(14,848)	
Accrued expenses	(723)	
Net cash provided by (used) in operations...........	16,263	
Investing Activities		
Capital expenditures, including purchases and development of properties	(57,056)	
Proceeds from sale of oil and gas properties..	28,938	
Acquisition of minority interest.....................	(2,679)	
Proceeds from sale of foreign subsidiaries..........	-	
Net cash provided by (used) in investing activities.	(30,797)	

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

	Years Ended	
	2001	20
		(In th
Financing Activities		
Proceeds from issuance of common stock...............	16	
Proceeds from long-term borrowings	29,995	
Payments on long-term borrowings	(9,326)	
Deferred financing fees	-	
Net cash (used in) provided by financing activities..	20,685	
Increase (decrease) in cash	6,151	
Effect of exchange rate changes on cash..............	(550)	
Increase (decrease) in cash	5,601	
Cash at beginning of year	2,004	
Cash at end of year..................................	$ 7,605	$
Supplemental Disclosures		
Supplemental disclosures of cash flow information:		
Interest paid	$ 31,752	$

Taxes paid............................	$ 505	$

Supplemental schedule of non-cash investing and financing activities:

In May 2001 the Company issued 3,386,488 shares of common stock upon the expiration of the CVRs issued in connection with the December 1999 exchange.

In September 2001 the Company issued 3,990,565 shares of common stock and options and paid $2,679,000 million in cash in connection with the acquisition of the minority interest in Old Grey Wolf. (See Note 4.)

Decrease in oil and gas properties and other assets..	$ (2,925)
Decrease in deferred income tax liability...........	$ 1,091
Increase in stockholders equity.....................	$ (9,246)
Decrease in minority interest in foreign subsidiary..	$ 13,759

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

	Years End	
	2001	
	(In	
Net income (loss)..	$ (19,718)	$
Other Comprehensive income (loss):		
Hedging derivatives (net of tax) - See Note 16	(566)	
Reclassification adjustment for settled hedge contracts, net of taxes..	-	
Change in fair market value of outstanding hedge positions net of taxes	-	
	-	
Foreign currency translation adjustment		
Reclassification of foreign currency translation adjustment relating to the sale of foreign subsidiaries.............	-	
Effect of change in exchange rate..........................	-	
Other comprehensive income (loss)...............................	(8,762)	
Comprehensive income (loss).....................................	$ (28,480)	$

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Significant Accounting Policies

Nature of Operations

Abraxas Petroleum Corporation (the "Company" or "Abraxas") is an independent energy company engaged in the exploration for and the acquisition, development, and production of crude oil and natural gas primarily along the Texas Gulf Coast, in the Permian Basin of western Texas and in western Canada. The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

The consolidated financial statements include the accounts of the Company and its wholly-owned foreign subsidiary, Grey Wolf Exploration Inc. ("New Grey Wolf"). In January 2003, the Company sold all of the common stock of its wholly-owned foreign subsidiaries, Canadian Abraxas Petroleum Limited ("Canadian Abraxas") and Grey Wolf Exploration Inc. ("Old Grey Wolf"). Certain oil and gas properties were retained and transferred into New Grey Wolf which was incorporated in January 2003. The operations of Canadian Abraxas and Old Grey Wolf are included in the consolidated financial statements through January 23, 2003.

New Grey Wolf's assets and liabilities are translated to U.S. dollars at period-end exchange rates. Income and expense items are translated at average rates of exchange prevailing during the period. Translation adjustments are accumulated as a separate component of shareholders' equity.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Management believes that it is reasonably possible that estimates of proved crude oil and natural gas revenues could significantly change in the future.

Concentration of Credit Risk

Financial instruments, which potentially expose the Company to credit risk consist principally of trade receivables and crude oil and natural gas price swap agreements. Accounts receivable are generally from companies with significant oil and gas marketing activities. The Company performs ongoing credit evaluations and, generally, requires no collateral from its customers.

Cash and Equivalents

Cash and cash equivalents includes cash on hand, demand deposits and short-term investments with original maturities of three months or less.

Accounts Receivable

Accounts receivable are reported net of an allowance for doubtful accounts of approximately $77,000 and $11,000 at December 31, 2002 and 2003, respectively. The allowance for doubtful accounts is determined based on the Company's historical losses, as well as a review of certain accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

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Equipment Inventory

Equipment inventory principally consists of casing, tubing, and compression equipment and is carried at cost.

Oil and Gas Properties

The Company follows the full cost method of accounting for crude oil and natural gas properties. Under this method, all direct costs and certain indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized crude oil and natural gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of crude oil and natural gas properties, as adjusted for asset retirement obligations, less related deferred taxes, are limited, by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10 percent, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Excess costs are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of crude oil and natural gas properties, except in unusual circumstances.

Unproved properties represent costs associated with properties on which the Company is performing exploration activities or intends to commence such activities. These costs are reviewed periodically for possible impairments or reduction in value based on geological and geophysical data. If a reduction in value has occurred, costs being amortized are increased. The Company believes that the unproved properties will be substantially evaluated in six to thirty-six months and it will begin to amortize these costs at such time. During 2001, 2002 and 2003 the Company capitalized $164,000, $152,000 and $49,000 of interest expense respectively, based on the cost of major development projects in progress.

Other Property and Equipment

Other property and equipment are recorded on the basis of cost. Depreciation of other property and equipment is provided over the estimated useful lives using the straight-line method. Major renewals and betterments are recorded as additions to the property and equipment accounts. Repairs that do not improve or extend the useful lives of assets are expensed.

Hedging

The Company periodically enters into agreements to hedge the risk of future crude oil and natural gas price fluctuations. Such agreements are primarily in the form of price floors and collars, which limit the impact of price fluctuations with respect to the Company's sale of crude oil and natural gas. The Company does not enter into speculative hedges. Gains and losses on such hedging activities are recognized in oil and gas production revenues when hedged production is sold. The net cash flows related to any recognized gains or losses associated with these hedges are reported as cash flows from operations. If the hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period as the physical production required by the contract is delivered.

Statement of Financial Accounting Standards, ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," was effective for the Company on January 1, 2001. SFAS 133, as amended and interpreted, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. All derivatives, whether designated in hedging relationships or not, will be required to be recorded on the balance sheet at fair value. If the derivative is designated a fair-value hedge, the changes in the fair value of the derivative and the hedged item will be recognized in earnings. If the derivative is designated a cash-flow hedge, changes in the fair value of the derivative will be recorded in other comprehensive income (OCI) and will be recognized in the income statement when the hedged item affects earnings. SFAS 133 defines new requirements for designation and documentation of hedging relationships as well as ongoing effectiveness assessments in order to use hedge accounting. For a derivative that does not qualify as a hedge, changes in fair value will be recognized in earnings.

Stock-Based Compensation

The Company accounts for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion ("APB") No. 25, "Accounting for Stock Issued to Employees," (APB No. 25) and related interpretations. Accordingly, compensation cost for stock options is measured as the excess, if any, of the quoted market price of the Company's stock at the date of the grant over the amount an employee must pay to acquire the stock.

Effective July 1, 2000, the Financial Accounting Standards Board ("FASB") issued FIN 44, "Accounting for Certain Transactions Involving Stock Compensation," an interpretation of APB No. 25. Under the interpretation, certain modifications to fixed stock option awards which were made subsequent to December 15, 1998, and were not exercised prior to July 1, 2000, require that the awards be accounted for as variable until they are exercised, forfeited, or expired. In March 1999, the Company amended the exercise price to $2.06 on all options with an existing exercise price greater than $2.06. The Company recognized a credit of $2.8 million during 2001 as stock-based compensation. The credit for the year ended December 31, 2001 was due to a decline in the Company's common stock price. There was no stock based compensation for the year ended December 31, 2002. In January 2003, in connection with the restructuring (see note 2), the Company amended the exercise price to $0.66 on certain options with an existing exercise price greater than $0.66. The Company recognized stock-based compensation expense of approximately $1.1 million during 2003.

Pro forma information regarding net income (loss) and earnings (loss) per share is required by SFAS 123, "Accounting for Stock-Based Compensation, (SFAS 123)" which also requires that the information be determined as if the Company has accounted for its employee stock options granted subsequent to December 31, 1995 under the fair value method prescribed by SFAS No. 123. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions for 2001, 2002 and 2003, risk-free interest rates of 3.5%, 1.50% and 1.5%, respectively; dividend yields of -0-%; volatility factors of the expected market price of the Company's common stock of .35, and a weighted-average expected life of the option of ten years.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because the Company's employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not necessarily provide a reliable single measure of the fair value of its employee stock options.

For purposes of pro forma disclosures, the estimated fair value of the options is amortized to expense over the options' vesting period. The Company's pro forma information follows:

		Year Ended De		
		2001		2
Net income (loss) as reported	$	(19,718)	$	(11
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects		(2,767)		
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		(1,284)		
Pro forma net income (loss)	$	(23,769)	$	(11
Earnings (loss) per share:				
Basic - as reported	$	(0.76)	$	
Basic - pro forma	$	(0.92)	$	
Diluted - as reported	$	(0.76)	$	(
Diluted - pro forma	$	(0.92)	$	

Foreign Currency Translation

The functional currency for Canadian Abraxas and Grey Wolf (Old and New) is the Canadian dollar ($CDN). The Company translates the functional currency into U.S. dollars ($US) based on the current exchange rate at the end of the period for the balance sheet and a weighted average rate for the period on the statement of operations. Translation adjustments are reflected as accumulated other comprehensive income (loss) in the consolidated financial statement of stockholders' deficit.

Fair Value of Financial Instruments

The Company includes fair value information in the notes to consolidated financial statements when the fair value of its financial instruments is materially different from the book value. The Company assumes the book value of those financial instruments that are classified as current approximates fair value because of the short maturity of these instruments. For noncurrent financial instruments, the Company uses quoted market prices or, to the extent that there are no available quoted market prices, market prices for similar instruments.

Restoration, Removal and Environmental Liabilities

The Company is subject to extensive Federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component are fixed or reliably determinable.

Revenue Recognition

The Company recognizes crude oil and natural gas revenue from its interest in producing wells as crude oil and natural gas is sold from those wells, net of royalties. Revenue from the processing of natural gas is recognized in the period the service is performed. The Company utilizes the sales method to account for gas production volume imbalances. Under this method, income is recorded based on the Company's net revenue interest in production taken for delivery. The Company had no material gas imbalances at December 31, 2003.

Deferred Financing Fees

Deferred financing fees are being amortized on a level yield basis over the term of the related debt arrangements.

Income Taxes

The Company records deferred income taxes using the liability method. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse.

New Accounting Pronouncements

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights held under lease or other contractual arrangement associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of such mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights held under lease or other contractual arrangement associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify approximately $3.1 million and $4.2 million at December 31, 2002 and December 31, 2003, respectively, out of oil and gas properties and into a separate intangible assets line item. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full-cost accounting rules.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS 143 is effective for us January 1, 2003. SFAS 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense in the accompanying consolidated financial statements.

The Company adopted SFAS 143 effective January 1, 2003. For the year ended December 31, 2003 the Company recorded a charge of $395,341 for the cumulative effect of the change in accounting principle and a liability of $1.3 million. During 2003, the Company charged approximately $379,000 to expense related to the accretion of the liability. The impact on each of the prior periods was not material.

The following table summarizes the Company's asset retirement obligation transactions during the following years:

	2003	2002
Beginning asset retirement obligation................	$ 3,946	$ 4,
Additions related to new properties..................	973	
Deletions related to property disposals..............	(3,921)	(
Accretion expense..................................	379	
Ending asset retirement obligation..................	$ 1,377	$ 3,

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS 144). Effective January 1, 2002, the Company adopted SFAS 144. SFAS 144 retains the requirement to recognize an impairment loss only where the carrying value of a long-lived asset is not recoverable from its undiscounted cash flows and to measure such loss as the difference between the carrying amount and fair value of the asset. SFAS 144, among other things, changes the criteria that have to be met to classify an asset as held-for-sale and requires that operating losses from discontinued operations be recognized in the period that the losses are incurred rather than as of the measurement date. This new standard had no impact on the Company's consolidated financial statements for the year ended December 31, 2003.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS 146). SFAS 146 requires costs associated with exit of disposal activities to be recognized when they are incurred rather than at the date of commitment to an exit or disposal plan. The Company is currently evaluating the impact the standard will have on its results of operations and financial condition. The effective date of this standard has not been determined by the FASB.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 149, among other things, clarifies the circumstances under which a contract with an initial net investment meets the characteristic of a derivative and amends the definition of an "underlying" to conform it to language used in FIN 45. SFAS 149 is effective for contracts entered into or modified after June 30, 2003. The Company adopted this statement effective July 1, 2003. Implementation of this new standard did not have an effect on the Company's consolidated financial position or results of operations.

In November 2002 the FASB issued FASB Interpretation No. 45 (FIN 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN 45 elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees that it has issued, including loan guarantees such as standby letters of credit. It also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligations it has undertaken in issuing the guarantee. The Interpretation does not specify the subsequent measurement of the guarantor's recognized liability over the term of the related guarantee. The guidance in FIN 45 does not apply to certain guarantee contracts, such as those issued by insurance companies or for a lessee's residual value guarantee embedded in a capital lease. The provisions related to recognizing a liability at inception of the guarantee for the fair value of the guarantor's obligations would not apply to product warranties or to guarantees accounted for as derivatives. The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002, regardless of the guarantor's fiscal year-end. FIN 45 specifies additional disclosures effective for financial statements of interim or annual periods ending after December 15, 2002. This new standard did not have an effect on the Company's consolidated financial position or results of operations.

In January 2003 the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable-Interest Entities (VIEs".) FIN 46 establishes the definition of VIEs to encompass a broader group of entities than those previously considered special-purpose entities (SPEs). FIN 46 specifies the criteria under which it is appropriate for an investor to consolidate VIEs; in order for an investor to consolidate a VIE, the entity must fall within the definition of VIE and the investor must fall within the definition of primary beneficiary, both newly defined terms under this interpretation. The revised effective date of FIN 46 for public companies with VIEs meeting certain conditions will be the end of the first interim or annual period ending after

December 15, 2003. In December 2003 the FASB issued FASB Interpretation no. 46(R), which expanded and clarified the guidelines of FIN 46. This new standard did not have an effect on the Company's consolidated financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, entitled "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). This statement is effective for financial instruments entered into or modified after May 31, 2003, and is otherwise effective at the beginning of the first interim period beginning after June 15, 2003. The Company has no financial instruments affected by SFAS 150, therefore adoption by the Company as of July 1, 2003 will not impact the Company's financial statements.

2. Restructuring transactions

In January 2003, the Company completed the following restructuring transactions:

- o The closing of the sale of the capital stock of Canadian Abraxas Petroleum and Old Grey Wolf, to a Canadian royalty trust for approximately $138 million.

- o The closing of a new senior credit agreement consisting of a term loan facility of $4.2 million and a revolving credit facility of up to $50 million with an initial borrowing base of $49.9 million, of which $42.5 million was used to fund the exchange offer described below and the remaining availability will be used to fund the continued development of our existing crude oil and natural gas properties.

- o The closing of an exchange offer, pursuant to which Abraxas paid $264 in cash and issued $610 principal amount of new 11 1/2 % Secured Notes due 2007, Series A, referred to herein as New Notes, and 31.36 shares of Abraxas common stock for each $1,000 in principal amount of the outstanding 11 1/2 % Senior Secured Notes due 2004, Series A, and 11 1/2 % Senior Notes due 2004, Series D, issued by Abraxas and Canadian Abraxas, which were tendered and accepted in the exchange offer. An aggregate of approximately $179.9 million in principal amount of the notes were tendered in the exchange offer and the remaining $11.1 million of notes not tendered were redeemed.

- o The repayment of Abraxas' 12? % Senior Secured Notes due 2003, principal amount of $63.5 million, plus accrued interest.

- o The repayment of Old Grey Wolf's senior secured credit facility with Mirant Canada Energy Capital Ltd. (Mirant Canada Facility) in the amount of approximately $46.3 million.

On February 23, 2004, the Company entered into an amendment to our existing senior credit agreement providing for two revolving credit facilities and a new non-revolving credit facility as described below. Subject to earlier termination on the occurrence of events of default or other events, the stated maturity date for these credit facilities is February 1, 2007. In the event of an early termination, we will be required to pay a prepayment premium, except in the limited circumstances described in the amended senior credit agreement.

First Revolving Credit Facility. Lenders under the amended senior credit agreement have provided Abraxas a revolving credit facility with a maximum borrowing base of up to $20 million. The Company's current borrowing base under this revolving credit facility is the full $20.0 million, subject to adjustments based on periodic calculations and mandatory prepayments under the senior credit agreement. The Company has borrowed $6.6 million under this revolving credit facility, which was used to refinance principal and interest on advances under it's preexisting revolving credit facility under the senior credit agreement, and to pay certain fees and expenses relating to the transaction. Outstanding amounts under this revolving credit facility bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 1.125%.

Second Revolving Credit Facility. Lenders under the amended senior credit agreement have provided a second revolving credit facility, with a maximum borrowing of up to $30 million. This revolving credit facility is not subject to a borrowing base. The Company has borrowed $30.0 million under this revolving credit facility, which was used to refinance principal and interest on advances under our preexisting revolving credit facility, and to pay certain transaction fees and expenses. Outstanding amounts under this revolving credit facility bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 3.00%.

Non-Revolving Credit Facility. The Company has borrowed $15.0 million pursuant to a non-revolving credit facility, which was used to repay the preexisting term loan under it's senior credit agreement, to refinance principal and interest on advances under the preexisting revolving credit facility, and to pay certain transaction fees and expenses. This non-revolving credit facility is not subject to a borrowing base. Outstanding amounts under this credit facility bear interest at the prime rate announced by Wells Fargo Bank, N.A. plus 8.00%.

Covenants. Under the amended senior credit agreement, we are subject to customary covenants and reporting requirements. Certain financial covenants require us to maintain minimum ratios of consolidated EBITDA (as defined in the amended senior credit agreement) to adjusted fixed charges (which includes certain capital expenditures), minimum ratios of consolidated EBITDA to cash interest expense, a minimum level of unrestricted cash and revolving credit availability, minimum hydrocarbon production volumes and minimum proved developed hydrocarbon reserves. In addition, if on the day before the end of each fiscal quarter the aggregate amount of our cash and cash equivalents exceeds $2.0 million, we are required to repay the loans under the amended senior credit agreement in an amount equal to such excess. The amended senior credit agreement also requires us to enter into hedging agreements on not less than 40% or more than 75% of our projected oil and gas production. We are also required to establish deposit accounts at financial institutions acceptable to the lenders and we are required to direct our customers to make all payments into these accounts. The amounts in these accounts will be transferred to the lenders upon the occurrence and during the continuance of an event of default under the amended senior credit agreement.

In addition to the foregoing and other customary covenants, the amended senior credit agreement contains a number of covenants that, among other things, restrict our ability to:

- incur additional indebtedness;
- create or permit to be created liens on any of our properties;
- enter into change of control transactions;
- dispose of our assets;
- change our name or the nature of our business;
- make guarantees with respect to the obligations of third parties;
- enter into forward sales contracts;

- o make payments in connection with distributions, dividends or redemptions relating to our outstanding securities, or

- o make investments or incur liabilities.

Security. The obligations of Abraxas under the amended senior credit agreement continue to be secured by a first lien security interest in substantially all of Abraxas' assets, including all crude oil and natural gas properties.

Guarantees. The obligations of Abraxas under the amended senior credit agreement continue to be guaranteed by Abraxas' subsidiaries, Sandia Oil & Gas, Sandia Operating, Wamsutter, Grey Wolf, Western Associated Energy and Eastside Coal. The guarantees under the amended senior credit agreement continue to be secured by a first lien security interest in substantially all of the guarantors' assets, including all crude oil and natural gas properties.

Events of Default. The amended senior credit agreement contains customary events of default, including nonpayment of principal or interest, violations of covenants, inaccuracy of representations or warranties in any material respect, cross default and cross acceleration to certain other indebtedness, bankruptcy, material judgments and liabilities, change of control and any material adverse change in our financial condition.

The following presents the summarized results of operations for the years ended December 31, 2001, 2002, and for the period ended January 23, 2003, for the Canadian properties which were not retained after the transaction in January 2003.

	Year ended December 31, 2001	2002	2003
Total revenue	$ 41,468	$ 32,013	$ 3,275
Income (loss) from operations before income tax	(102)	(87,378)	1,250
Income tax expense (benefit)	1,897	(29,697)	377
Minority interest in income	(1,676)	--	--
Income (loss) from operations	$ (3,675)	$(57,681)	$ 873

Assets and liabilities related to the Canadian properties which were not retained after the January 2003 transaction:

	December 31, 2002
Assets:	
Cash...	$ 4,325
Accounts receivable..........................	4,016
Net property and equipment...................	54,468
Other..	11,438
	$ 74,247
Liabilities:	

Accounts payable and accrued liabilities........	$ 7,320
Long-tern debt.................................	45,964
Other..	3,413
	$ 56,697

Included in the loss from operations shown above is interest expense of $7.6 million and $9.5 million, and general and administrative expense of $1.5 million and $1.7 million for the years ended December 31, 2001 and 2002, respectively. The interest expense represents the amounts relating to an Old Grey Wolf senior credit facility which was repaid in conjunction with the transactions described above and the amounts related to the balance of certain notes (approximately $52.6 million) which had historically been reflected by Canadian Abraxas.

3. Long-Term Debt

As described in Note 2, the First Lien Notes were redeemed in January 2003. The Old Notes and the Second Lien Notes were either redeemed or exchanged for cash, common stock and New Notes in January 2003. Additionally, the 9.5% Mirant Canada Energy Capital, Ltd. credit facility, with a balance outstanding at December 31, 2002 of $45.9 million, was repaid in connection with the sale of the common stock of Old Grey Wolf in January 2003.

The following is a brief description of the Company's debt as of December 31, 2002 and 2003, respectively:

	December 31	
	2002	2003
	(in thousands)	
11.5% Senior Notes due 2004 ("Old Notes")	$ 801	$ -
12.875% Senior Secured Notes due 2003 ("First Lien Notes")	63,500	-
11.5% Second Lien Notes due 2004 ("Second Lien Notes")............	190,178	-
9.5% Senior Credit Facility ("Grey Wolf Facility") providing for borrowings up to approximately US $96 million (CDN $150 million). Secured by the assets of Old Grey Wolf and non-recourse to Abraxas......................................	45,964	-
11.5% Secured Notes due 2007 ("New Notes")........................	-	137,2
Senior Credit Agreement	-	47,3
	300,443	184,6
Less current maturities	63,500	
	$ 236,943	$ 184,6

(a) After the transactions described in Note 2, for financial reporting purposes, the New Notes were reflected at the carrying value of the Second Lien Notes and Old Notes prior to the exchange of $191.0 million, net of the cash offered in the exchange of $47.5 million and net of the fair market value related to equity of $3.8 million offered in the exchange transaction. The face amount of the New Notes is $120.5 million at December 31, 2003 including $10.8 million in new notes issued for interest.

Old Notes. Interest on the Old Notes was payable semi-annually in arrears on May 1 and November 1 of each year at the rate of 11.5% per annum. The Old Notes were redeemable, in whole or in part, at the option of the Company.

First Lien Notes. Interest on the First Lien Notes was payable semi-annually in arrears on March 15 and September 15 of each year at the rate of 12.875% per annum.

Second Lien Notes. Interest on the Second Lien Notes was payable semi-annually in arrears on May 1 and November 1, commencing May 1, 2000 at the rate of 11.5% per annum.

New Notes - 11 1/2% Secured Notes. The New Notes accrue interest from the date of issuance, at a fixed annual rate of 11 1/2%, payable in cash semi-annually on each May 1 and November 1, commencing May 1, 2003, provided that, if we fail, or are not permitted pursuant to our new senior secured credit agreement or the intercreditor agreement between the trustee under the indenture for the New Notes and the lenders under the new senior secured credit agreement, to make such cash interest payments in full, we will pay such unpaid interest in kind by the issuance of additional New Notes with a principal amount equal to the amount of accrued and unpaid cash interest on the New Notes plus an additional 1% accrued interest for the applicable period. Upon an event of default, the New Notes accrue interest at an annual rate of 16.5%.

The New Notes are secured by a second lien or charge on all of our current and future assets, including, but not limited to, all of our crude oil and natural gas properties. All of Abraxas' current subsidiaries, Sandia Oil & Gas, Sandia Operating (a wholly-owned subsidiary of Sandia Oil & Gas), Wamsutter, New Grey Wolf, Western Associated Energy and Eastside Coal, are guarantors of the New Notes, and all of Abraxas' future subsidiaries will guarantee the New Notes. If Abraxas cannot make payments on the New Notes when they are due, the guarantors must make them instead.

The New Notes and related guarantees

- are subordinated to the indebtedness under the senior credit agreement;
- rank equally with all of Abraxas' current and future senior indebtedness; and
- rank senior to all of Abraxas' current and future subordinated indebtedness, in each case, if any.

The New Notes are subordinated to amounts outstanding under the new senior secured credit agreement both in right of payment and with respect to lien priority and are subject to an intercreditor agreement.

Abraxas may redeem the New Notes, at its option, in whole at any time or in part from time to time, at redemption prices expressed as percentages of the principal amount set forth below. If Abraxas redeems all or any New Notes, it must also pay all interest accrued and unpaid to the applicable redemption date. The redemption prices for the New Notes during the indicated time periods are as follows:

Period	Percentage
From January 24, 2004 to June 23, 2004	97.1674%
From June 24, 2004 to January 23, 2005	98.5837%
Thereafter	100.0000%

Under the indenture, we are subject to customary covenants which, among other things, restrict our ability to:

- o borrow money or issue preferred stock;
- o pay dividends on stock or purchase stock;
- o make other asset transfers;
- o transact business with affiliates;
- o sell stock of subsidiaries;
- o engage in any new line of business;
- o impair the security interest in any collateral for the notes;
- o use assets as security in other transactions; and
- o sell certain assets or merge with or into other companies.

In addition, we are subject to certain financial covenants including covenants limiting our selling, general and administrative expenses and capital expenditures, a covenant requiring Abraxas to maintain a specified ratio of consolidated EBITDA, as defined in the agreements, to cash interest and a covenant requiring Abraxas to permanently, to the extent permitted, pay down debt under the new senior secured credit agreement and, to the extent permitted by the new senior secured credit agreement, the New Notes or, if not permitted, paying indebtedness under the new senior secured credit agreement.

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The indenture contains customary events of default, including nonpayment of principal or interest, violations of covenants, inaccuracy of representations or warranties in any material respect, cross default and cross acceleration to certain other indebtedness, bankruptcy, material judgments and liabilities, change of control and any material adverse change in our financial condition.

Senior Credit Agreement. In connection with the financial restructuring, Abraxas entered into a new senior credit agreement providing a term loan facility and a revolving credit facility which was amended in February 2004. A summary description of the senior credit agreement as amended, is set forth in Note 2.

4. Acquisitions and Divestitures

Acquisition of Minority Interest in Old Grey Wolf

In September 2001, the Company completed a tender offer for the minority interest in Old Grey Wolf, acquiring the approximately 52% of capital stock that was not previously owned by the Company. The Company issued 3,990,565 common shares and 588,916 stock options, valued together at approximately $9.2 million. Additionally, the Company incurred direct costs of approximately $2.7 million related to the acquisition. The elimination of the minority interest through an acquisition at a purchase price less than Old Grey Wolf's book value in the Company's consolidated financial statements had the effect of reducing the property and other assets balances by $2.9 million and deferred income taxes by $1.1 million.

5. Property and Equipment

The major components of property and equipment, at cost, are as follows:

	Estimated Useful Life	December 31 2002	20
	Years	(In thousands)	
Land, buildings, and improvements	15	$ 331	$
Crude oil and natural gas properties	-	529,047	3
Natural Gas Processing.........................	18	38,735	
Equipment and other	7	5,123	
		$ 573,236	$ 3

6. Stockholders' Equity

Common Stock

In 1994, the Board of Directors adopted a Stockholders' Rights Plan and declared a dividend of one Common Stock Purchase Right ("Rights") for each share of common stock. The Rights are not initially exercisable. Subject to the Board of Directors' option to extend the period, the Rights will become exercisable and will detach from the common stock ten days after any person has become a beneficial owner of 20% or more of the common stock of the Company or has made a tender offer or Exchange Offer (other than certain qualifying offers) for 20% or more of the common stock of the Company.

Once the Rights become exercisable, each Right entitles the holder, other than the acquiring person, to purchase for $40 a number of shares of the Company's common stock having a market value of two times the purchase price. The Company may redeem the Rights at any time for $.01 per Right prior to a specified period of time after a tender or Exchange Offer. The Rights will expire in November 2004, unless earlier exchanged or redeemed.

Treasury Stock

In March 1996, the Board of Directors authorized the purchase in the open market of up to 500,000 shares of the Company's outstanding common stock, the aggregate purchase price not to exceed $3,500,000. During the year ended December 31, 2000, 38,800 shares with an aggregate cost of $78,000 were purchased. During the years ended December 31, 2001, 2002 and 2003, the Company did not purchase any shares of its common stock for treasury stock.

7. Stock Option Plans and Warrants

Stock Options

The Company grants options to its officers, directors, and other employees under various stock option and incentive plans.

During 2001, the Company's stockholders approved an amendment to the Abraxas Petroleum Corporation 1994 Long Term Incentive Plan to increase the number of shares of Abraxas common stock reserved for issuance under the plan to 5,000,000 shares. The additional shares were necessary to accommodate the grant of Abraxas options to Old Grey Wolf option holders in connection with the acquisition of the minority interest in Old Grey Wolf in September 2001 (see Note 4), and for the re-issuance of outstanding options granted under the Abraxas Petroleum Corporation 2000 Long Term Incentive Plan, which was terminated in 2001. The options were re-issued at the same exercise price and term as the original issuances.

The Company's various stock option plans have authorized the grant of options to management, employees and directors for up to approximately 5.7 million shares of the Company's common stock. All options granted have ten year terms and vest and become fully exercisable over three to four years of continued service at 25% to 33% on each anniversary date. At December 31, 2003 approximately 2.3 million options remain available for grant.

A summary of the Company's stock option activity, and related information for the three years ended December 31, follows:

	2001		2002		
	Options (000s)	Weighted-Average Exercise Price	Options (000s)	Weighted-Average Exercise Price (1)	Options (000s)
Outstanding-beginning of year	4,042	$ 3.37	4,942	$ 3.28	3,305
Granted	918	2.81	521	0.68	360
Exercised	(8)	1.95	-	-	(129
Forfeited/Expired	(10)	1.79	(2,158)	4.84	(172
Outstanding-end of year	4,942	$ 3.28	3,305	$ 1.85	3,364
Exercisable at end of year	2,259	$ 2.65	2,136	$ 1.91	2,331
Weighted-average fair value of options granted during the year		$ 1.19		$ 0.63	

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(1) In September 2001, the Abraxas Petroleum Corporation 2000 Long Term Incentive Plan was terminated, and options granted under the plan were reissued under the Abraxas Petroleum Corporation 1994 Long Term Incentive Plan at the same option price and term.

The following table represents the range of option prices and the weighted average remaining life of outstanding options as of December 31, 2003:

Options outstanding	
Weighted Weighted	

Exercise price	Number outstanding	average remaining life	average exercise price	Number exercisable
$0.50 - 0.97	2,761,160	6.0	$ 0.71	1,886,043
$1.01 - 1.63	259,900	7.8	1.22	123,050
$2.06 - 2.21	311,958	2.1	2.07	305,979
$3.39 - 4.83	31,407	6.9	4.77	16,406

In January 2003, in connection with the financial restructuring discussed in Note 2, approximately 1.9 million options with a strike price greater that $0.66 were re-priced to $0.66.

Stock Awards

In addition to stock options granted under the plans described above, the 1994 Long-Term Incentive Plan also provides for the right to receive compensation in cash, awards of common stock, or a combination thereof. There were no awards in 2001, 2002 or 2003.

The Company also has adopted the Restricted Share Plan for Directors which provides for awards of common stock to non-employee directors of the Company who did not, within the year immediately preceding the determination of the director's eligibility, receive any award under any other plan of the Company. There were no direct awards of common stock in 2001, 2002 or 2003.

Stock Warrants

In 2000, the Company issued 950,000 warrants in conjunction with a consulting agreement. Each is exercisable for one share of common stock at an exercise price of $3.50 per share. These warrants have a four-year term beginning July 1, 2000. The Company paid cash compensation of $191,000 during 2001 under the consulting agreement.

At December 31, 2003, the Company has approximately 3.3 million shares reserved for future issuance for conversion of its stock options, warrants, and incentive plans for the Company's directors, employees and consultants.

8. Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax liabilities and assets are as follows:

	December 3	
	2002	
	(In thousan	
Deferred tax liabilities:		
U.S. full cost pool	$ -	$
Total deferred tax liabilities	-	

Deferred tax assets:	
U.S. full cost pool	2,168
Capital loss carryforward	-
Original issue discount on certain debt obligations	-
Canadian full cost pool	9,787
Depletion	2,778
Net operating losses ("NOL")	58,811
Investment in foreign subsidiaries	32,038
Other	1,364
Total deferred tax assets	106,946
Valuation allowance for deferred tax assets	(99,126)
Net deferred tax assets	7,820
Net deferred tax liabilities (assets)	$ (7,820)

Significant components of the provision (benefit) for income taxes are as follows:

	2001	2002
Current:		
Federal	$ 505	$ -
Foreign	-	-
	$ 505	$ -

	2001	2002
Deferred:		
Federal	$ -	$ -
Foreign	1,897	26,697
	$1,897	$ 26,697

At December 31, 2003 the Company had, subject to the limitation discussed below, $100.6 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire from 2003 through 2022 if not utilized. In connection with the January 2003 transactions described in Note 2, certain of the loss carryforward may be utilized.

At December 31, 2002, the Company was no longer permanently reinvested with respect to its foreign subsidiaries, see Note 2. As a result, the Company recorded net deferred tax assets of $32.0 million related to its investment in foreign subsidiaries, offset by an equivalent valuation allowance due to uncertainties as to the future utilization of these amounts.

In addition to the Section 382 limitations, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, the Company has established a valuation allowance of $99.1 million and $71.3 million for deferred tax assets at December 31, 2002 and 2003, respectively. , The reconciliation of income tax computed at the U.S. federal statutory tax rates to income tax expense is:

	December 31		
	2001	2002	
	(In thousands)		
Tax (expense) benefit at U.S. statutory rates (35%)	$ 5,318	$ 51,878	$
(Increase) decrease in deferred tax asset valuation allowance	(4,907)	(59,456)	
Write-down of non-tax basis assets....	(2,194)	(7,009)	
Higher effective rate of foreign operations.........................	(136)	7,349	
Percentage depletion	596	683	
Investment in foreign subsidiaries ..	-	35,604	
Other	(1,079)	648	
	$ (2,402)	$ 29,697	$

9. Related Party Transactions

Accounts receivable - Other includes approximately $51,211 and $35,558 as of December 31, 2002 and 2003, respectively, representing amounts due from officers relating to advances made to employees.

On July 29, 2003 the Company acquired all of the shares of the capital stock of Wind River Resources Corporation which owned an airplane. The sole shareholder of Wind River was the Company's President. The consideration for the purchase was 106,977 shares of Abraxas common stock and $35,000 in cash. Simultaneously with this transaction, the airplane was sold. The airplane had previously been made available to Abraxas' employees for business use.

The Company paid Wind River a total of $314,000, $345,000 and $132,000 in 2001, 2002 and 2003, through July 29, respectively, for Wind River's operating cost associated with the Company's use of the plane.

10. Commitments and Contingencies

Operating Leases

During the years ended December 31, 2001, 2002 and 2003 the Company incurred rent expense related to leasing office facilities of approximately $519,000, $236,000 and $464,000 respectively. Future minimum rental payments are as follows at December 31, 2003.

2004..	$ 416,000
2005..	412,000

2006..	223,000
2007..	161,000
Thereafter......................................	161,000
	$ 1,373,000

Litigation and Contingencies

In 2001 the Company and a partnership were named in a lawsuit filed in U.S. District Court in the District of Wyoming. The claim asserts breach of contract, fraud and negligent misrepresentation by the Company related to the responsibility for year 2000 ad valorem taxes on crude oil and natural gas properties sold by the Company and the Partnership. In February 2002, a summary judgment was granted to the plaintiff in this matter and a final judgment in the amount of $1.3 million was entered. The Company has filed an appeal. The Company believes these charges are without merit. The Company has established a reserve in the amount of $845,000, which represents the Company's interest in the judgment. In 2002 the Company recorded $201,000 in other expense representing its share of the ongoing legal cost related to this matter.

In 2003, Abraxas and Leam Drilling Systems each filed suit against the other relating to certain drilling services that Leam contracted to provide Abraxas. Abraxas believes that the services were provided in a grossly negligent manner and that Leam committed fraud. Leam has asserted that Abraxas failed to pay approximately $639,000 for services rendered. The cases are pending in Bexar County and Ward County, Texas.

Additionally, from time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2003, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

11. Earnings per Share

Basic earnings (loss) per share excludes any dilutive effects of options, warrants and convertible securities and is computed by dividing income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings (loss) per share are computed similar to basic, however diluted earnings per share reflects the assumed conversion of all potentially dilutive securities.

The following table sets forth the computation of basic and diluted earnings per share:

	2001	2002	
Numerator:			
Net income (loss) before effect of accounting			
change	$ (19,718,000)	$ (118,527,000)	$
Cumulative effect of accounting change..........	-	-	
	$ (19,718,000)	$ (118,527,000)	
Denominator:			
Denominator for basic earnings per share - weighted-average shares	25,788,571	29,979,397	
Effect of dilutive securities:			

Stock options and warrants....................	-	-
Dilutive potential common shares Denominator for diluted earnings per share - adjusted weighted-average shares and assumed conversions..................................	25,788,571	29,979,397
Basic earnings (loss) per share:		
Net income (loss) before cumulative effect of accounting change...............................e	$ (0.76)	$ (3.95)
Cumulative effect of accounting change..........	-	-

Net income (loss) per common share...............	$ (0.76)	$ (3.95)	$
Diluted earnings (loss) per share:			
Net income (loss) before cumulative effect of accounting change...............................e	$ (0.76)	$ (3.95)	$
Cumulative effect of accounting change..........	-	-	
Net income (loss) per common share - diluted.	$ (0.76)	$ (3.95)	$

For the year ended December 31, 2001and 2002, 4.3 million shares and 5.9 million shares respectively, were excluded from the calculation of diluted earnings per share since their inclusion would have been anti-dilutive.

12. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 2002 and 2003 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter
	(In thousands, except per share data)		
Year Ended December 31, 2002			
Net revenue...........................	$ 11,807	$ 14,235	$ 11,061
Operating income (loss)...............	(735)	(115,879)	490
Net income (loss).....................	(8,699)	(95,690)	(8,438)
Net income (loss) per common share - basic and diluted..................	$ (0.29)	$ (3.19)	$ (0.28)
Year Ended December 31, 2003			
Net revenue...........................	$ 13,111	$ 8,430	$ 8,430
Operating income (loss)...............	5,646	1,927	2,694
Net income (loss).....................	62,702	(2,346)	(2,702)
Net income (loss) per common share - basic.............................	$ 1.83	$ (0.07)	$ (0.08)
Net income (loss) per common share - diluted...........................	$ 1.82	$ (0.07)	$ (0.08)

During the second quarter of 2002, the Company incurred a ceiling limitation write-down of approximately $116.0 million.

13. Benefit Plans

The Company has a defined contribution plan (401(k)) covering all eligible employees of the Company. The Company did not contribute to the plan in 2002 or 2003. The employee contribution limitations are determined by formulas, which limit the upper one-third of the plan members from contributing amounts that would cause the plan to be top-heavy. The employee contribution is limited to the lesser of 20% of the employee's annual compensation or $11,000 in 2002 and $12,000 in 2003.

14. Guarantor Condensed Consolidation Financial Statements

The following table presents condensed consolidating balance sheets of Abraxas, as a parent company, and its significant subsidiaries, Canadian Abraxas and Old Grey Wolf, as of December 31, 2002 and 2003 and the related consolidating statements of operations and cash flows for the years ended December 31, 2001, 2002 and 2003. Canadian Abraxas was a guarantor of the First Lien Notes ($63.5 million) and jointly and severally liable with Abraxas for the Second Lien Notes ($190.2 million) and the Old Notes ($801,000). Old Grey Wolf was a non-guarantor with respect to the First Lien Notes and the Old Notes.

The First Lien Notes and the Second Lien Notes were retired in connection with the financial restructuring transactions which occurred in January 2003. New Grey Wolf is a guarantor of the New Notes, there are no non-guarantor subsidiaries, accordingly, condensed consolidating balance sheets of Abraxas, as parent and its subsidiary New Grey Wolf are presented as of December 31, 2003 and the related consolidating statements of operations and cash flows for the year ended December 31, 2003.

Condensed Consolidating Parent Company and Subsidiaries Balance Sheet
December 31, 2003
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Subsidiary (New Grey Wolf)	Reclassifi-catio and eliminations
Assets:			
Cash	$ -	$ 493	$ -
Accounts receivable, less allowance for doubtful accounts.....................	14,101	903	(6,681)
Equipment inventory	782	-	-
Other current assets	418	154	-
Total current assets.............	15,301	1,550	(6,681)
Property and equipment - net................	76,021	35,542	-
Deferred financing fees, net	4,410	-	-
Deferred income taxes and other assets	27,551	-	(27,257)
Total assets	$ 123,283	$ 37,092	$ (33,938)
Liabilities and Stockholders' deficit:			
Current liabilities:			

Accounts payable	$ 7,075	$ 8,652	$ (6,681)
Accrued interest	2,340	-	-
Other accrued expenses	1,228	-	-
Total current liabilities	10,643	8,652	(6,681)
Long-term debt	184,649	-	-
Future site restoration	776	601	-
	196,068	9,253	(6,681)
Stockholders' equity (deficit)	(72,785)	27,839	(27,257)
Total liabilities and stockholders' equity (deficit)	$ 123,283	$ 37,092	$ (33,938)

(1) Includes amounts for insignificant U.S. subsidiaries, Sandia Oil and Gas, Sandia Operating, Western Energy Associates, East Side Coal and Wamsutter, which are guarantors of the New Notes.

Condensed Consolidating Parent Company, Restricted Subsidiaries and Non-Guarantor
December 31, 2002
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(2)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)	Re ca el
Assets:				
Current assets:				
Cash	$ 557	$ 2,188	$ 2,137	$
Accounts receivable, less allowance for doubtful accounts	4,482	4,782	11,938	
Equipment inventory	860	142	12	
Other current assets	316	682	242	
Total current assets	6,215	7,794	14,329	

Property and equipment - net	74,435	38,858	37,101	
Deferred financing fees, net	2,970	688	2,013	
Deferred income taxes and other assets	108,558		7,820	
Total assets	$ 192,178	$47,340	$61,263	$
Liabilities and Stockholders' deficit:				
Current liabilities:				
Accounts payable	$ 15,928	$ 766	$ 6,398	
Accrued interest	5,000	1,009	-	
Other accrued expenses	1,162	-	-	
Current maturities of long-term debt	63,500	-	-	
Total current liabilities	85,590	1,775	6,398	
Long-term debt	138,350	52,629	45,964	
Future site restoration	-	3,171	775	

	223,940	57,575	53,137
Stockholders' equity (deficit)..................	(31,762)	(10,235)	8,126
Total liabilities and stockholders' equity (deficit).......................................	$ 192,178	$ 47,340	$ 61,263 $

(2) Includes amounts for insignificant U.S. subsidiaries, Sandia Oil and Gas, Sandia Operating, Western Energy Associates, East Side Coal and Wamsutter, which are guarantors of the First and Second Lien Notes. Sandia is also a guarantor of the Old Notes. Additionally, these subsidiaries are designated as Restricted Subsidiaries along with Canadian Abraxas.

Condensed Consolidating Parent Company and Subsidiary Statement of Operations
For the year ended December 31, 2003
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(1)	Subsidiary (New Grey Wolf)	Reclassifi-cation and eliminations
Revenues:			
Oil and gas production revenues	$ 29,710	$ 8,395	$ -
Gas processing revenues......................	-	133	-
Rig revenues	663	-	-
Other	7	111	-
	30,380	8,639	-
Operating costs and expenses:			
Lease operating and production taxes	8,342	1,257	-
Depreciation, depletion, and amortization	7,608	3,195	-
Rig operations	609	-	-
General and administrative	3,995	1,365	-
Stock-based compensation......................	1,106	-	-
	21,660	5,817	-
Operating income (loss).........................	8,720	2,822	-
Other (income) expense:			
Interest income	(30)	-	-
Amortization of deferred financing fees........	1,630	48	-
Interest expense.............................	16,323	632	-
Financing costs..............................	4,406	-	-
Gain on sale of foreign subsidiaries..........	(68,933)	-	-
Other	100	674	-
	(46,504)	1,354	-
Income (loss) before income tax and cumulative effect of accounting change...................	55,224	1,468	-
Income tax expense (benefit).....................	-	377	-
Cumulative effect of accounting change...........	395	-	-

Net income (loss)	$ 54,829	$ 1,091	$ -

Condensed Consolidating Parent Company, Restricted Subsidiary and Non-Guarantor Statem
For the year ended December 31, 2002
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(2)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)	Re ca el
Revenues:				
Oil and gas production revenues	$ 20,835	$ 14,726	$ 15,301	$
Gas processing revenues	-	1,955	465	
Rig revenues	635	-	-	
Other	71	152	180	
	21,541	16,833	15,946	
Operating costs and expenses:				
Lease operating and production taxes	7,639	3,751	3,850	
Depreciation, depletion, and amortization	9,194	10,633	6,712	
Proved property impairment	28,178	60,501	27,314	
Rig operations	567	-	-	
General and administrative	4,045	1,312	1,527	
	49,623	76,197	39,403	
Operating income (loss)	(28,082)	(59,364)	(23,457)	
Other (income) expense:				
Interest income	(92)	-	-	
Amortization of deferred financing fees	1,325	366	404	
Interest expense	24,689	6,665	2,796	
Other	1,168	-	-	
	27,090	7,031	3,200	
Income (loss) before income tax	(55,172)	(66,395)	(26,657)	
Income tax expense (benefit)	-	(18,522)	(11,175)	
Net income (loss)	$ (55,172)	$ (47,873	$ (15,482)	$

Condensed Consolidating Parent Company, Restricted Subsidiary and Non-Guarantor Statem

For the year ended December 31, 2001
(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(2)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)	Re ca el
Revenues:				
Oil and gas production revenues	$ 34,934	$ 24,308	$ 13,959	
Gas processing revenues	-	2,008	430	
Rig revenues	756	-	-	
Other	85	471	292	
	35,775	26,787	14,681	
Operating costs and expenses:				
Lease operating and production taxes	9,302	6,836	2,478	
Depreciation, depletion, and amortization	12,336	14,707	5,441	
Proved property impairment....................	-	2,638	-	
Rig operations	702	-	-	
General and administrative	3,742	1,720	983	
General and administrative (Stock-based Compensation)..............................	(2,767)	-	-	
	23,315	25,901	8,902	
Operating income (loss).........................	12,460	886	5,779	
Other (income) expense:				
Interest income	(1,242)	-	-	
Amortization of deferred financing fees........	1,907	361	-	
Interest expense..............................	25,086	7,117	484	
Other	1,052	-	-	
	26,803	7,478	484	
Income (loss) before income tax	(14,343)	(6,592)	5,295	
Income tax expense (benefit)....................	505	(80)	1,977	
Minority interest in income of consolidated foreign subsidiary...........................	-	-	1,676	
Net income (loss)..............................	$ (14,848)	$ (6,512)	$ 1,642	$

Condensed Consolidating Parent and Subsidiary Statement of Cash Flow
For the year ended December 31, 2003
(In thousands)

Abraxas Petroleum Corporation Inc. Parent Company(1)	Subsidiary (New Grey Wolf)	Reclassifi -cations and eliminations

Operating Activities			
Net income (loss)	$ 54,829	$ 1,091	$ -
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Gain on sale of foreign subsidiaries....	(68,933)	-	-
Depreciation, depletion, and amortization	7,608	3,195	-
Non-cash interest and financing costs...	16,422	-	-
Deferred income tax (benefit) expense...		377	-
Amortization of deferred financing fees.	1,630	48	-
Stock-based compensation................	1,106	-	-
Changes in operating assets and liabilities:			
Accounts receivable	(7,850)	394	6,010
Equipment inventory	78	-	-
Other	295	-	-
Accounts payables and accrued expenses	6,294	7,266	(6,010)
Net cash provided by (used in)operations.....	11,479	12,371	-
Investing Activities			
Capital expenditures, including purchases and development of properties	(9,194)	(9,155)	-
Proceeds from sale of foreign subsidiaries...	85,810	-	-
Net cash provided (used) by investing activities...............................	76,616	(9,155)	-
Financing Activities			
Proceeds from issuance of common stock.......	177	-	-
Proceeds from long-term borrowings...........	43,051	291	-
Payments on long-term borrowings	(131,283)	(7,261)	-
Deferred financing fees.....................	(597)	-	-
Net cash provided (used) by financing activities...............................	(88,652)	(6,970)	-
Effect of exchange rate changes on cash	-	(78)	-
Increase (decrease) in cash	(557)	(3,832)	-
Cash at beginning of year	557	4,325	-
Cash at end of year.........................	$ -	$ 493	$ -

Condensed Consolidating Parent, Restricted Subsidiary and Non-Guarantor Statemen
For the year ended December 31, 2002
(In thousands)

Abraxas Petroleum Corporation Inc. Parent Company(2)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)	Re ca el

Operating Activities				
Net income (loss)	$ (55,172)	$ (47,873)	$ (15,482)	$
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation, depletion, and amortization	9,194	10,633	6,712	
Proved property impairment	28,178	60,501	27,314	
Deferred income tax (benefit) expense...	-	(18,522)	(11,175)	
Amortization of deferred financing fees.	1,325	366	404	
Changes in operating assets and liabilities:				
Accounts receivable	18,088	(3,187)	1,114	
Equipment inventory	201	-	-	
Other	381	(177)	(78)	
Accounts payables and accrued expenses	(47)	479	(3,251)	
Net cash provided by (used in)operations.....	2,148	2,220	5,555	
Investing Activities				
Capital expenditures, including purchases and development of properties	(5,070)	(4,926)	(28,916)	
Proceeds from sale of oil and gas properties..............................	9,725	21,789	2,362	
Net cash provided (used) by investing activities..............................	4,655	16,863	(26,554)	
Financing Activities				
Proceeds from long-term borrowings...........	-	-	20,551	
Payments on long-term borrowings	(8,176)	(18,262)	-	
Deferred financing fees.....................	(1,663)	146	(22)	
Net cash provided (used) by financing activities..............................	(9,839)	(18,116)	20,529	
Effect of exchange rate changes on cash	-	(24)	(163)	
Increase (decrease) in cash	(3,036)	943	(630)	
Cash at beginning of year	3,593	1,245	2,767	
Cash at end of year.........................	$ 557	$ 2,188	$ 2,137	$

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Condensed Consolidating Parent, Restricted Subsidiary and Non-Guarantor Statemen

For the year ended December 31, 2001

(In thousands)

	Abraxas Petroleum Corporation Inc. Parent Company(2)	Restricted Subsidiary (Canadian Abraxas)	Non-Guarantor Subsidiary (Old Grey Wolf)	Re ca el
Operating Activities				

Net income (loss)	$ (14,848)	$ (6,512)	$ 1,642	
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Minority interest in income of foreign subsidiary...........................	-	-	1,676	
Loss on sale of equity investment.......	845	-	-	
Depreciation, depletion, and amortization	12,336	14,707	5,441	
Proved property impairment..............	-	2,638	-	
Deferred income tax (benefit) expense...	-	(80)	1,977	
Amortization of deferred financing fees.	1,907	361	-	
Stock-based compensation	(2,767)	-	-	
Changes in operating assets and liabilities:				
Accounts receivable	28,804	(9,721)	(6,390)	
Equipment inventory	(76)	-	-	
Other	(281)	-	175	
Accounts payables and accrued expenses	(12,915)	(2,254)	(402)	
Net cash provided (used) by operating activities	13,005	(861)	4,119	
Investing Activities				
Capital expenditures, including purchases and development of properties	(19,126)	(15,313)	(22,617)	
Proceeds from sale of oil and gas properties...............................	9,677	15,882	3,379	
Acquisition of minority interest	(2,679)	-	-	
Net cash provided (used) by investing activities...............................	(12,128)	569	(19,238)	
Financing Activities				
Proceeds form issuance of common stock.......	16	-	-	
Proceeds from long-term borrowings	11,700	-	18,295	
Payments on long-term borrowings	(9,326)	-	-	
Net cash provided (used) by financing activities	2,390	-	18,295	
	3,267	(292)	3,176	
Effect of exchange rate changes on cash	-	(141)	(409)	
Increase (decrease) in cash	3,267	(433)	2,767	
Cash at beginning of year	326	1,678	-	
Cash at end of year.........................	$ 3,593	$ 1,245	$ 2,767	$

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15. Business Segments

The Company conducts its operations through two geographic segments, the United States and Canada, and is engaged in the acquisition, development, and production of crude oil and natural gas in each country. The Company's significant operations are located in the Texas Gulf Coast, the Permian Basin of western Texas, and Canada. Identifiable assets are those assets used in the operations of the segment. Corporate assets consist primarily of deferred financing fees and other property and equipment. The Company's revenues are derived primarily from the sale of crude oil, condensate, natural gas liquids, and natural gas to marketers and refiners and from processing fees from the custom processing of natural gas. As a general policy, collateral is not required for receivables; however, the credit of the Company's customers is regularly assessed. The Company is not aware of any significant credit risk relating to its customers and has not experienced significant credit losses associated with such receivables.

In 2003, three customers accounted for approximately 67% of consolidated oil and natural gas production revenue. Three customers accounted for approximately 80% of United States revenue and three customer accounted for approximately 91% of revenue in Canada. In 2002, four customers accounted for approximately 79% of consolidated oil and natural gas production revenue. Three customers accounted for approximately 77% of United States revenue and one customer accounted for approximately 80% of revenue in Canada. In 2001, three customers accounted for approximately 41% of oil and natural gas production revenues. Three customers accounted for approximately 76% of United States revenue and five customers accounted for approximately 76% of revenue in Canada.

Business segment information about the Company's 2001 operations in different geographic areas is as follows:

	U.S.	Canada	Tot
		(In thousands)	
Revenues	$ 35,775	$ 41,468	$
Operating profit...........................	$ 13,795	$ 6,665	$
General corporate			
Net interest expense and amortization of deferred financing fees			
Other expense...			
Loss before income taxes..			$
Identifiable assets at December 31, 2001 ...	$ 124,993	$ 174,063	$
Corporate assets			
Total assets			$

Business segment information about the Company's 2002 operations in different geographic areas is as follows:

	U.S.	Canada	Tot
		(In thousands)	
Revenues	$ 21,541	$ 32,779	$
Operating loss.............................	$ (23,677)	$ (82,821)	$ (
General corporate			
Net interest expense and amortization of deferred financing fees			

Other expense..			
Loss before income taxes...			$ (
Identifiable assets at December 31, 2002....	$ 81,025	$ 94,059	$
Corporate assets			
Total assets			$

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Business segment information about the Company's 2003 operations in different geographic areas is as follows:

	U.S.	Canada	Tot
		(In thousands)	
Revenues	$ 30,380	$ 8,639	$
Operating income...........................	$ 14,001	$ 2,822	$
General corporate			
Net interest expense, financing cost and amortization of deferred financing fees			
Gain on sale of foreign subsidiaries..			
Other income (expense) - net..			
Cumulative effect of accounting change......................................			
Income before income taxes..			$
Identifiable assets at December 31, 2003....	$ 84,228	$ 37,092	$
Corporate assets			
Total assets			$

16. Hedging Program and Derivatives

On January 1, 2001, the Company adopted SFAS 133 "Accounting for Derivative Instruments and Hedging Activities" SFAS 133 as amended by SFAS 137 "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB 133" and SFAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities. Gains and losses on hedging instruments related to accumulated Other Comprehensive Income (Loss) and adjustments to carrying amounts on hedged production are included in natural gas or crude oil production revenue in the period that the related production is delivered. The Company has not elected hedge accounting for the floors that are in place as of December 31, 2003, accordingly, adjustments to the carrying value of the instruments are recognized in oil and gas income in the current period.

Under the terms of the Company's senior credit agreement, the Company is required to maintain hedging agreements with respect to not less than 25% nor more than 75% of it crude oil and natural gas production for a rolling six month period. The credit agreement was amended in February 2004, see Note 2, increasing the minimum hedged position to 40% of our estimated production. As of December 31, 2003 the Company's hedging positions were as follows:

Time Period	Notional Quantities	Price
March 1, 2003 - February 29, 2004	5,000 MMBtu of natural gas production per day	Floor of $4.50
March 1, 2004 - April 30, 2004	2,000 MMBtu of natural gas production per day	Floor of $4.00
March 1, 2004 - April 30, 2004	500 Bbl of crude oil production per day	Floor of $22.00
May 2004	2,000 MMbtu of natural gas production per day	Floor of $4.00
May 2004	500 Bbls of crude oil production per day	Floor of $22.00
June 2004	800 Bbls of crude oil production per day	Floor of $22.00
July 2004	2,000 MMbtu of natural gas production per day	Floor of $4.00
July 2004	500 Bbl of crude oil production per day	Floor of $22.00

All hedge transactions are subject to the Company's risk management policy, approved by the Board of Directors. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, the Company assesses whether the derivatives that are used in hedging transactions are effective in offsetting changes in cash flows of hedged items.

The fair value of the hedging instrument was determined based on the base price of the hedged item and NYMEX forward price quotes. As of December 31, 2003, a commodity price increase of 10% would have resulted in an unfavorable change in the fair market value of approximately $2,000 and a commodity price decrease of 10% would have resulted in a favorable change in fair market value of approximately $2,000.

17. Proved Property Impairment

In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the year, or alternatively, if prices subsequent to that date have increased, a price near the periodic filing date of the Company's financial statements. As of December 31, 2001, the Company's net capitalized costs of oil and gas properties exceeded the present value of its estimated proved reserves by $71.3 million ($38.9 million on the U.S. properties and $32.4 million on the Canadian properties). These amounts were calculated considering 2001 year-end prices of $19.84 per barrel for oil and $2.57 per Mcf for gas as adjusted to reflect the expected realized prices for each of the full cost pools. The Company did not adjust its capitalized costs for its U.S. properties because subsequent to December 31, 2001, oil and gas prices increased such that capitalized costs for its U.S. properties did not exceed the present value of the estimated proved oil and gas reserves for its U.S. properties as determined using increased realized prices on March 22, 2002 of $24.16 per Bbl for oil and $2.89 per Mcf for gas. During the second quarter of 2002, the Company had a ceiling limitation write-down of approximately $116.0 million. At December 31, 2003, the net capitalized cost of crude oil and natural gas properties did not exceed the present value of our estimated reserves, as such, no write-down was recorded.

18. Supplemental Oil and Gas Disclosures (Unaudited)