SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
(Mark One)

[X]ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 1996

[ ]TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number 0-19118

ABRAXAS PETROLEUM CORPORATION

(Exact name of Registrant as specified in its charter)

Nevada	74-2584033
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

500 N. Loop 1604 East, Suite 100
San Antonio, Texas 78232

Registrant's telephone number, including area code (210) 490-4788

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:
None

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
Common Stock, par value $.01 per share

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

The aggregate market value of the voting stock (which consists solely of shares of Common Stock) held by non-affiliates of the registrant as of March 21, 1997, (based upon the average of the $10.50 per share "Bid" and $10.75 per share "Asked" prices), was approximately $45,911,049 on such date.

The number of shares of the issuer's Common Stock, par value $.01 per share, outstanding as of March 21, 1997 was 5,732,101 shares of which 4,878,049 shares were held by non-affiliates.

Documents Incorporated by Reference: Portions of the registrant's Proxy Statement relating to the 1997 Annual Meeting of Shareholders to be held on May 23, 1997 have been incorporated by reference herein (Part III).

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PART I

Item 1. Business

General

Abraxas Petroleum Corporation, a Nevada corporation ("Abraxas" or the "Company") 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, the Permian Basin of western Texas, Canada and Wyoming. The Company's business strategy is to acquire and develop producing crude oil and natural gas properties and related assets that contain the potential for increased value through exploitation and development. The Company utilizes a disciplined acquisition strategy, focusing its efforts on producing properties and related assets possessing the following characteristics: a concentration of operations; significant, quantifiable development potential; historically low operating expenses; and the potential to reduce general and administrative expenses per barrel of crude oil equivalent ("BOE"). Since December 31, 1990, the Company has made 16 acquisitions of crude oil and natural gas producing properties totaling an estimated 46.0 million barrels of crude oil equivalent ("MMBOE") of proved reserves at an average acquisition cost of approximately $3.83 per BOE.

Since January 1996, the Company has had operations in the United States and Canada and since November 1996, the Company's operations have consisted of two segments: exploration and production and natural gas gathering and processing. The revenues and operating earnings for each country and each industry segment and the identifiable assets attributable to each country and each industry segment for the year ended December 31, 1996 are set forth in Note 15 to the Notes to Consolidated Financial Statements included elsewhere herein.

At December 31, 1996, the Company operated 364 wells and owned non-operated interests in 155 net wells. Average net daily production for the year ended December 31, 1996 was 1,985 barrels ("Bbls") of crude oil and natural gas liquids and 17,397 thousand cubic feet ("Mcf") of natural gas. The Company's proved reserves and present value (discounted at 10%) of estimated future net cash flows (before income taxes) of proved crude oil and natural gas reserves ("Present Value of Proved Reserves") has increased from an estimated 889 thousand barrels of crude oil equivalent ("MBOE") and $11.9 million, respectively, at January 1, 1991 to an estimated 47.5 MMBOE and $415.9 million, respectively, at January 1, 1997. Of the Company's proved reserves at January 1, 1997, 86.6% were classified as proved developed reserves and 87.5% of the Present Value of Proved Reserves at such date was attributable to such proved developed reserves. The Company also owned varying interests in 13 natural gas processing plants or compression facilities with capacity of 128.0 MMCF per day and 197 miles of natural gas gathering systems.

Since January 1, 1991, the Company's principal means of growth has been through the acquisition and subsequent development and exploitation of producing properties and related assets. The Company intends to continue its growth strategy emphasizing reserve additions through its exploitation efforts. There can be no assurance that attractive acquisition opportunities will arise, that the Company will be able to consummate acquisitions in the future or that sufficient external or internal funds will be available to fund the Company's acquisitions. The Company may also use, where appropriate, it's equity securities as all or part of the consideration for such acquisitions.

Although the Company intends to devote most of its resources to the exploitation and development of the producing properties acquired, the Company intends to selectively participate in the exploration for new reserves of crude oil and natural gas. The Company intends to develop prospects internally and to participate with industry partners in prospects generated by other parties in its exploration activities.

The Company periodically evaluates, and from time to time has elected to sell, certain of its mature producing properties. Such sales enable the Company to maintain financial flexibility, reduce overhead and redeploy the proceeds therefrom to activities that the Company believes to have a potentially higher financial return. See "Recent Activities".

Principal Areas Of Activity

Texas Gulf Coast and South Texas

Portilla Field, San Patricio County, Texas The Company acquired a 50% working interest in the Portilla Field in April 1993 and the remaining 50% in November 1996. The field, discovered in the 1950's by Superior Oil Company, produces from numerous Miocene, Frio and Vicksburg age sands from depths between 4,000 feet and 9,000 feet. A report prepared by independent petroleum engineers showed estimated net proved reserves of 3.3 million barrels ("MMBbls") of crude oil and natural gas liquids and 5.0 billion cubic feet ("Bcf") of natural gas from this field, with a Present Value of Proved Reserves of $36.1 million at January 1, 1997. For the year ended December 31, 1996, the field produced an average of approximately 611 net Bbls of crude oil and 219 net Bbls of natural gas liquids per day and sold approximately 1,867 net Mcf of natural gas per day from 33 active wells. The Company also owns a 100% interest in a natural gas processing plant with capacity of approximately 20 MMcf per day. The Company is the operator of the natural gas processing plant and all of the wells in this field.

East White Point Field, San Patricio County, Texas. The Company acquired an approximate 30% working interest in this field in April 1993 and an additional 30% interest in November 1996. The field produces crude oil and natural gas from numerous sands in the Lower Frio formation from 9,000 feet to 13,000 feet. A report prepared by independent petroleum engineers showed estimated net proved reserves of 3.2 MMBbls of crude oil and natural gas liquids and 29.7 Bcf of natural gas from this field with a Present Value of Proved Reserves of $60.0 million at January 1, 1997. The Company operates 11 wells and Marathon Oil Company ("Marathon") operates another 10 wells in which the Company has an interest in this field. For the year ended December 31, 1996, the field produced an average of approximately 184 net Bbls of crude oil and 250 net Bbls of natural gas liquids per day and sold 3,266 net Mcf of natural gas per day from 19 active wells. The Company also owns an approximate 43% interest in a natural gas processing plant. The Company is the operator of this natural gas processing plant.

Stedman Island Field, Nueces County, Texas. The Company acquired a 25% working interest in this field in April 1993, an additional 25% in October 1995 and the remaining 50% in November 1996. The field produces crude oil and natural gas from the Frio sands at depths of 8,500 to 10,000 feet. A report prepared by independent petroleum engineers showed estimated net proved reserves of 519.7 MBbls of crude oil and natural gas liquids and 10.1 Bcf of natural gas from this field with a Present Value of Proved Reserves of $16.5 million at January 1, 1997. During 1996, the field produced an average of approximately 50 net Bbls of crude oil and natural gas liquids and 966 net Mcf of natural gas per day.

Permian Basin - West Texas

Delaware Area (Howe, ROC, Block 16, Taurus, Gomez, N.E. Oates and Nine Mile Draw Fields). In connection with the acquisition of producing properties located in West Texas from a group of sellers in July 1994 (the "West Texas Properties"), the Company acquired working interests ranging from 18% to 100% in 35 wells, 29 of which are operated by the Company. The fields produce from Devonian, Wolfcamp, Ellenburger and Cherry Canyon sands from depths ranging from 6,500 feet to 17,600 feet. A report prepared by independent petroleum engineers showed estimated net proved reserves of 4.6 MMBbls of crude oil and natural gas liquids and 29.9 Bcf of natural gas in these fields, with a Present Value of Proved Reserves of $91.9 million at January 1, 1997. During 1996 the Company drilled 22 wells in this area and produced an average of 6,509 net MCF of natural gas and 650 net Bbls of crude oil and natural gas liquids per day from these fields.

Sharon Ridge and Westbrook Fields, Scurry and Mitchell Counties, Texas. The Company drilled its first wells in the Westbrook Field in 1978 and operated approximately 40 wells prior to 1992. The two fields produce crude oil from Permian age carbonates between 1,700 feet and 3,500 feet. In 1992, the Company acquired working interests ranging from 57.5% to 100% and became the operator of 124 wells in the Sharon Ridge Field, which is adjacent to the Westbrook Field. A report prepared by independent petroleum engineers showed estimated net proved reserves of 1.4 MMBbls of crude oil and natural gas liquids from this field, with a Present Value of Proved Reserves of $8.4 million at January 1, 1997. For the year ended December 31, 1996, the Company produced an average of approximately 171 net Bbls of crude oil per day from these fields. The Company is currently investigating waterflooding and development drilling to enhance production.

Canada

In January 1996, the Company invested $3.0 million in Grey Wolf Exploration Ltd., ("Grey Wolf"), a privately held Canadian corporation, which, in turn, invested in newly-issued shares of Cascade Oil and Gas Ltd., ("Cascade"), an Alberta-based corporation whose shares are traded on the Alberta Stock Exchange. The Company owns 78% of the outstanding capital stock of Grey Wolf and, through Grey Wolf, the Company owns 52% of the outstanding capital stock of Cascade. Cascade owns 4.3 net producing crude oil and natural gas wells and 12,000 net acres of undeveloped leases in southwestern Saskatchewan. A report prepared by independent petroleum engineers showed estimated net proved reserves of 120 MBbls of crude oil, with a Present Value of Proved Reserves of $1.3 million (CDN) approximately $950,000 (U.S.), at January 1, 1997.

In November 1996, the Company's wholly owned subsidiary, Canadian Abraxas Petroleum Limited ("Canadian Abraxas") acquired 100% of the outstanding capital stock of CGGS Canadian Gas Gathering Systems Inc. ("CGGS"). Canadian Abraxas owns producing properties in western Canada consisting primarily of natural gas reserves and interests ranging from 10% to 100% in 197 miles of natural gas gathering systems and 11 natural gas processing plants or compression facilities (the "Canadian Abraxas Plants"), four of which are operated by Canadian Abraxas. The Canadian Abraxas Properties consist of 154,968 gross acres (86,327 net acres) and 120 gross wells (68.8 net wells), 48 of which are operated by Canadian Abraxas. As of January 1, 1997, the Canadian Abraxas Properties had total proved reserves of 10,382 MBOE (88.5% natural gas) with Present Value of Proved Reserves of $85.4 million, 88.6% of which was attributable to proved developed reserves. The Canadian Abraxas Plants had aggregate net natural gas processing capacity of 98.3 MMcf per day at December 31, 1996. For the twelve months ended December 31, 1996, the Canadian Abraxas Plants processed an average of 182.8 gross MMcf (65.7 net MMcf) of natural gas per day, of which 19.6% (9.7% net) was custom processed for third parties.

Wyoming

On September 30, 1996, the Company acquired producing properties in the Wamsutter area of southwestern Wyoming (the "Wyoming Properties"). The Wyoming Properties consist of 19,587 gross acres (14,091 net acres) and 25 gross wells (20.4 net wells), 22 of which are operated by the Company. In addition, the Company acquired various overriding royalty interests in four wells. As of January 1, 1997, the Wyoming properties had proven reserves of 10,570 MBOE (69.2% natural gas) with Present Value of Proved Reserves of $108.2 million, 89.5% of which was attributable to proved developed reserves.

Markets and Customers

The revenues generated by the Company's operations are 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 received by the Company for its crude oil and natural gas production and the level of such production are subject to wide fluctuations and depend on numerous factors beyond the Company's control including seasonality, the condition of the United States and the Canadian economies (particularly the manufacturing sector), foreign imports, political conditions in other 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 the Company's proved reserves and the Company's revenues, profitability and cash flow.

In order to manage its exposure to price risks in the marketing of its crude oil and natural gas, the Company from time to time has 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, the Company 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 its futures position and sell its production to a customer. Such contracts may expose the Company to the risk of financial loss in certain circumstances, including instances where production is less than expected, the Company's 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. Such contracts may also restrict the ability of the Company to benefit from unexpected increases in crude oil and natural gas prices.

In connection with the reacquisition of the Portilla and Happy Fields in November 1996, the Company assumed certain commodity swaps on variable volumes of oil and gas. The agreements settle monthly with amounts either due to or from Christiania Bank, New York Branch ("Christiania") based on the differential between a fixed and a variable price for crude oil and natural gas. During 1997, the approximate monthly volume of crude oil sales subject to this swap agreement is 15,800 barrels at a fixed price of $17.20. This agreement reduces to approximately 13,200 barrels per month in 1998, 11,000 barrels per month in 1999, 9,100 barrels per month in 2000 and 8,200 barrels per month in 2001 until November 1. The fixed price paid to the Company over this five year period averages $17.55 per barrel. The natural gas component of this agreement calls for approximately 54,000 MMBTU per month at a fixed price of $1.80 during 1997 with volumes decreasing to 37,000 MMBTU per month in 1998, 24,000 MMBTU per month in 1999, 19,000 MMBTU per month in 2000, and 15,000 MMBTU per month in 2001 through October. The fixed price paid to the Company over this five year period averages $1.84 per MMBTU.

The Company has also entered into two fixed price agreements, each relating to approximately 3,750 net MMBTU per day of natural gas. The first of these two agreements expires on March 31, 1997 and calls for a fixed price of $1.52 per MMBTU being paid to the Company. The second agreement expires on October 31, 1997 and provides a fixed price of $1.42 per MMBTU to the Company.

The Company has also recently entered into a costless collar relating to 1,000 barrels a day of oil sales for the period February 1, 1997 through December 31, 1997. This agreement guarantees a minimum price of $19.00 per barrel to the Company and provides that any amount above $25.60 per barrel be remitted by the Company to the counterparty to the agreement.

Substantially all of the remainder of the Company's crude oil and natural gas is sold at current market prices under short term contracts, as is customary in the industry. During the year ended December 31, 1996, seven purchasers accounted for approximately 66% of the Company's crude oil and natural gas sales. The Company believes that there are numerous other companies available to purchase the Company's crude oil and natural gas and that the loss of any or all of these purchasers would not materially affect the Company's ability to sell crude oil and natural gas.

Risk Factors

Industry Conditions; Impact on Company's Profitability

The Company's revenues, profitability and future rate of growth are substantially dependent upon prevailing prices for crude oil and natural gas. Crude oil and natural gas prices can be extremely volatile and prior to 1996 were depressed by excess total domestic and imported supplies. While prices for crude oil and natural gas increased during 1996 and have remained at these levels during the first quarter of 1997, there can be no assurance that current price levels for crude oil and natural gas can be sustained. Prices are also affected by actions of state and local agencies, the United States and foreign governments and international cartels. These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of crude oil and natural gas. Any substantial or extended decline in the prices of crude oil and natural gas would have a material adverse effect on the Company's financial condition and results of operations, including reduced cash flow and borrowing capacity. All of these factors are beyond the control of the Company. Sales of crude oil and natural gas are seasonal in nature, leading to substantial differences in cash flow at various times throughout the year. Federal and state regulation of crude oil and natural gas production and transportation, general economic conditions, changes in supply and changes in demand all could adversely affect the Company's ability to produce and market its crude oil and natural gas. If market factors were to change dramatically, the financial impact on the Company could be substantial. The availability of markets and the volatility of product prices are beyond the control of the Company and thus represent a significant risk.

In addition, declines in crude oil and natural gas prices might, under certain circumstances, require a write-down of the book value of the Company's crude oil and natural gas properties. If such declines were severe enough, they could result in the occurrence of an event of default under the Company's outstanding indebtedness that could require the sale of some of the Company's producing properties under unfavorable market conditions or require the Company to seek additional equity capital. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources".

In order to manage its exposure to price risks in the marketing of its crude oil and natural gas, the Company from time to time has 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, the Company 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 its futures position and sell its production to a customer. Such contracts may expose the Company to the risk of financial loss in certain circumstances, including instances where production is less than expected, the Company's 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. Such contracts may also restrict the ability of the Company to benefit from unexpected increases in crude oil and natural gas prices.

Losses From Operations

The Company has experienced recurring losses. For the years ended December 31, 1993, 1994 and 1995, the Company recorded net losses of $2.4 million, $2.4 million and $1.2 million, respectively. Although the Company had net income of $ 1.5 million for the year ended December 31, 1996, there can be no assurance that the Company will not experience operating losses in the future.

Operating Hazards; Uninsured Risks

The nature of the crude oil and natural gas business involves certain operating hazards such as crude oil and natural gas blowouts, explosions, formations with abnormal pressures, cratering and crude oil spills and fires, any of which could result in damage to or destruction of crude oil and natural gas wells, destruction of producing facilities, damage to life or property, suspension of operations, environmental damage and possible liability to the Company. In accordance with customary industry practices, the Company maintains insurance against some, but not all, of such risks and some, but not all, of such losses. The occurrence of such an event not fully covered by insurance could have a material adverse effect on the financial condition and results of operations of the Company.

Leverage and Debt Service

The Company's level of indebtedness will have several important effects on its future operations including (i) a substantial portion of the Company's cash flow from operations will be dedicated to the payment of interest on its indebtedness and will not be available for other purposes; (ii) covenants contained in the Company's debt obligations will require the Company to meet certain financial tests and other restrictions which will limit its ability to borrow additional funds or to dispose of assets and may affect the Company's flexibility in planning for, and reacting to, changes in its business, including possibly limiting acquisition activities; and (iii) the Company's 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 may be limited.

As of December 31, 1996, the Company's total debt and stockholders' equity were approximately $215.0 million and $35.7 million, respectively. In addition, the Company had $20.0 million of unused borrowing capacity under the Credit Facility (as defined below) at December 31, 1996. The Company intends to incur additional indebtedness in the future in connection with acquiring, developing and exploiting producing properties, although the Company's ability to incur additional indebtedness may be limited by the terms of the indenture (the "Indenture") governing its 11.5% Senior Notes Due 2004 (the "Notes") and the Credit Facility.

The Company's ability to meet its debt service obligations and to reduce its total indebtedness will be dependent upon the Company's future performance, which will be subject to general economic conditions and to financial, business and other factors affecting the operations of the Company, many of which are beyond its control. Based upon the current level of operations and the historical production of the producing properties and related assets currently owned by the Company, the Company believes that its cash flow from operations as well as borrowing capabilities will be adequate to meet its anticipated requirements for working capital, capital expenditures, interest payments, scheduled principal payments and general corporate or other purposes for the foreseeable future. See the Company's Consolidated Financial Statements and the notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources." No assurance can be given, however, that the Company's business will continue to generate cash flow from operations at or above current levels or that the historical production of the producing properties and related assets currently owned by the Company can be sustained in the future.

If the Company is unable to generate cash flow from operations in the future to service its debt, it may be required to refinance all or a portion of its existing debt or to obtain additional financing. There can be no assurance that such refinancing would be possible or that any additional financing could be obtained. In addition, the Notes are subject to certain limitations on redemption.

The Company's Credit Facility ("the Credit Facility") with Bankers Trust Company, as agent, ING (U.S.) Capital Corporation, as co-agent and Union Bank of California, N.A. (collectively the "Banks") contains a number of covenants, including the following: (1) the ratio of current assets to current liabilities (exclusive of any part of the loan which is current) shall not be less than 1:1, (2) the ratio of (a) EBITDA to (b) Interest expense, measured as of the last day of any calendar quarter for the twelve month period then ended, shall not be less than 1.50 to 1.00 as of the last day of any calendar quarter through June 30, 1997 or to be less than 1.75 to 1.00 as of the last day of any calendar quarter after June 30, 1997 and (3) Consolidated Tangible Net Worth must be greater than $30,000,000 at any time. The Credit Facility also contains covenants related to maintaining corporate existence, maintaining title to all of the collateral free and clear of all liens except for the Banks liens and those permitted by the Banks, maintaining all mineral interests in good repair and in compliance with all laws, maintaining insurance, paying all taxes, not paying dividends except as required on the Company's Series 1995-B Preferred Stock and not selling any of the collateral securing the loans. The Company is currently in compliance with these covenants.

Restrictions Imposed by Terms of the Company's Indebtedness

The Indenture and the Credit Facility restrict, among other things, the Company's 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 the assets of the Company. In addition, the Credit Facility contains additional and more restrictive covenants. The Indenture and the Credit Facility also require the Company to maintain specified financial ratios and satisfy certain financial tests. The Company's ability to meet such financial ratios and tests may be affected by events beyond its control, and there can be no assurance that the Company will meet such ratios and tests. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources." A breach of any of these covenants could result in a default under the Indenture and/or the Credit Facility. Upon the occurrence of an event of default under the Credit Facility, the lenders thereunder could elect to declare all amounts outstanding under the Credit Facility, together with accrued interest, to be immediately due and payable. If the Company were unable to repay those amounts, such lenders could proceed against the collateral granted to them to secure that indebtedness. If the lenders under the Credit Facility acelerate the payment of such indebtedness, there can be no assurance that the assets of the Company would be sufficient to repay in full such indebtedness and the other indebtedness of the Company, including the Notes. Substantially all of the Company's U.S. assets, including, without limitation, working capital and interests in producing properties and related assets owned by the Company, and the proceeds thereof are pledged as security under the Credit Facility. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources."

Substantial Capital Requirements

The Company makes, and will continue to make, substantial capital expenditures for the acquisition, exploitation, development, exploration and production of crude oil and natural gas reserves. Historically, the Company has financed these expenditures primarily with cash flow from operations, bank borrowings and the offering of its equity securities. The Company believes that it will have sufficient capital to finance planned capital expenditures. If revenues or the Company's borrowing base under the Credit Facility decrease as a result of lower crude oil and natural gas prices, operating difficulties or declines in reserves, the Company may have limited ability to finance planned capital expenditures in the future. There can be no assurance that additional debt or equity financing or cash generated by operations will be available to meet these requirements. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources."

Integration of Operations; Foreign Operations

The Company's future operations and earnings will be largely dependent upon the Company's ability to integrate the operations of CGGS and the Wyoming Properties into the previous operations of the Company. The operations of CGGS and the Wyoming Properties vary in geography from that of the Company's previous operations, and with respect to CGGS, to some extent, in scope and type, from the Company's previous operations. There can be no assurance that the Company will be able to successfully integrate such operations with those of the Company, and a failure to do so would have a material adverse effect on the Company's financial position, results of operations and cash flows. Additionally, although the Company does not currently have any specific acquisition plans, the need to focus management's attention on integration of the new operations, as well as other factors, may limit the Company's ability to successfully pursue acquisitions or other opportunities related to its business for the foreseeable future. Also, successful integration of operations will be subject to numerous contingencies, some of which are beyond management's control. These contingencies include general and regional economic conditions, prices for crude oil and natural gas, competition and changes in regulation. Even if the Company is successful in integrating the new operations, the acquisition of CGGS in particular has significantly increased the Company's dependence on international operations, specifically those in Canada, and therefore the Company is subject to various additional political, economic and other uncertainties. Among other risks, the Company's operations are subject to the risks of restrictions on transfers of funds, export duties and quotas, domestic and international customs and tariffs, and changing taxation policies, foreign exchange restrictions, political conditions and governmental regulations. In addition, the Company will receive a substantial portion of its revenue in Canadian dollars. As a result, fluctuations in the exchange rates of the Canadian dollar with respect to the U.S. dollar could have an adverse effect on the Company's financial position, results of operations and cash flows. The Company may from time to time engage in hedging programs intended to reduce the Company's exposure to currency fluctuations.

Future Availability of Natural Gas Supply

To obtain volumes of committed natural gas reserves to supply the Canadian Abraxas Plants, the Company will contract to process natural gas with various producers. Future natural gas supplies available for processing at the Canadian Abraxas Plants will be affected by a number of factors that are not within the Company's control, including the depletion rate of natural gas reserves currently connected to the Canadian Abraxas Plants and the extent of exploration for, production and development of, and demand for natural gas in the areas in which the Company will operate. Long-term contracts will not protect the Company from shut-ins or supply curtailments by natural gas supplies. Although CGGS was historically successful in contracting for new natural gas supplies and in renewing natural gas supply contracts as they expired, there is no assurance that the Company will be able to do so on a similar basis in the future.

Shares Eligible for Future Sale

At March 21, 1997, the Company had 5,732,101 shares of Common Stock outstanding of which 854,052 shares were held by affiliates. Of the shares held by non-affiliates, 1,330,000 shares were sold in November 1995 in a private placement (the "Private Placement") of 1,330,000 units each consisting of one share of Common Stock and one Contingent Value Right ("CVR"). In addition, at March 21, 1997, the Company had 550,810 shares of Common Stock subject to outstanding options granted under certain stock option plans (of which 149,482 shares were vested at March 21, 1997), 437,500 shares issuable upon exercise of warrants and up to 1,995,000 shares of Common Stock issuable upon maturity of the CVRs in November 1997. The actual number of shares issuable upon maturity of the CVRs is dependent upon the difference between the target price (which is $12.50 in 1997) and the median of the averages of the closing bid prices of the Common Stock on the Nasdaq Stock Market during three consecutive 20-trading day periods immediately preceding the maturity date.

All of the shares of Common Stock held by affiliates are restricted or control securities under Rule 144 promulgated under the Securities Act of 1933, as amended (the "Securities Act"). The shares of the Common Stock issuable upon exercise of the stock options have been registered under the Securities Act. In addition, the Company has filed a registration statement covering the shares of the Common Stock issued in the Private Placement and the shares of Common Stock issuable upon maturity of the CVRs. All of such shares will be offered only by means of a prospectus. The shares of the Common Stock issuable upon exercise of the warrants are subject to certain registration rights and, therefore, will be eligible for resale in the public market after a registration statement covering such shares has been declared effective. Sales of shares of

Common Stock under Rule 144 or pursuant to a registration statement could have a material adverse effect on the price of the Common Stock and could impair the Company's ability to raise additional capital through the sale of its equity securities.

Competition

The Company encounters strong competition from major oil companies and independent operators in acquiring properties and leases for the exploration for, and production of, crude oil and natural gas. Competition is particularly intense with respect to the acquisition of desirable undeveloped crude oil and natural gas leases. The principal competitive factors in the acquisition of such undeveloped crude oil and natural gas leases include the staff and data necessary to identify, investigate and purchase such leases, and the financial resources necessary to acquire and develop such leases. Many of the Company's competitors have financial resources, staff and facilities substantially greater than those of the Company. In addition, the producing, processing and marketing of crude oil and natural gas is affected by a number of factors which are beyond the control of the Company, the effect of which cannot be accurately predicted.

The principal raw materials and 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. The Company must compete for such raw materials and resources with both major crude oil companies and independent operators. Although the Company believes its current operating and financial resources are adequate to preclude any significant disruption of its operations in the immediate future, the continued availability of such materials and resources to the Company cannot be assured.

The Company will 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. The Company's principal competitors will 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 the Company. Smaller local distributors may enjoy a marketing advantage in their immediate service areas. The Company will compete against other companies in its natural gas processing business both for supplies of natural gas and for customers to which it will sell its products. Competition for natural gas supplies is based primarily on location of natural gas gathering facilities and natural gas gathering plants, operating efficiency and reliability and ability to obtain a satisfactory price for products recovered. Competition for customers is based primarily on price and delivery capabilities.

Reliance on Estimates of Proved Reserves and Future Net Revenues; Depletion of Reserves

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond the control of the Company. The reserve data set forth in this report represent only estimates. In addition, the estimates of future net revenues from proved reserves of the Company and the present value thereof are based upon certain 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 Present Value of Proved Reserves for the crude oil and natural gas properties described in this report 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, 1996. The average sales prices as of such dates used for purposes of such estimates were $23.19 per Bbl of crude oil, $16.31 per Bbl of NGLs and $2.96 per Mcf of natural gas. Also assumed is the Company's making future capital expenditures of approximately $23.1 million in the aggregate necessary to develop and realize the value of proved undeveloped reserves on its properties. Any significant variance in these assumptions could materially affect the estimated quantity and value of reserves set forth herein. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" and "Business - Reserve Information."

Certain Business Risks

The Company intends to continue acquiring producing crude oil and natural gas properties or companies that own such properties. Although the Company performs a review of the acquired properties that it believes is consistent with industry practices, such reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, the Company will focus its review efforts on the higher-valued properties and will sample the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems nor will it permit the Company to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Furthermore, the Company must rely on information, including financial, operating and geological information, provided by the seller of the properties without being able to verify fully all such information and without the benefit of knowing the history of operations of all such properties.

In addition, a high degree of risk of loss of invested capital exists in almost all exploration and development activities which the Company undertakes. No assurance can be given that crude oil or natural gas will be discovered to replace reserves currently being developed, produced and sold, or that if crude oil or natural gas reserves are found, they will be of a sufficient quantity to enable the Company to recover the substantial sums of money incurred in their acquisition, discovery and development. Drilling activities are subject to numerous risks, including the risk that no commercially productive crude oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain. The Company's operations may be curtailed, delayed or cancelled as a result of numerous factors including title problems, weather condition, compliance with governmental requirements and shortages or delays in the delivery of equipment. The availability of a ready market for the Company's natural gas production depends on a number of factors, including, without limitation, the demand for and supply of natural gas, the proximity of natural gas reserves to pipelines, the capacity of such pipelines and governmental regulations.

Depletion of Reserves

The rate of production from crude oil and natural gas properties declines as reserves are depleted. Except to the extent the Company acquires additional properties containing proved reserves, conducts successful exploration and development activities or, through engineering studies, identifies additional behind-pipe zones or secondary recovery reserves, the proved reserves of the Company will decline as reserves are produced. Future crude oil and natural gas production is therefore highly dependent upon the Company's level of success in acquiring or finding additional reserves. See " - Certain Business Risks."

The Company's ability to continue to acquire producing properties or companies that own such properties assumes that major integrated oil companies and independent oil companies will continue to divest many of their crude oil and natural gas properties. There can be no assurance, however, that such divestitures will continue or that the Company will be able to acquire such properties at acceptable prices or develop additional reserves in the future. In addition, under the terms of the Indenture and the Credit Agreement, the Company's ability to obtain additional financing in the future for acquisitions and capital expenditures may be limited.

Title to Properties

As is customary in the crude oil and natural gas industry, the Company performs a minimal title investigation before acquiring undeveloped properties, which generally consists of obtaining a title report from legal counsel covering title to the major properties and due diligence reviews by independent landmen of the remaining properties. The Company believes that it has satisfactory title to such properties in accordance with standards generally accepted in the crude oil and natural gas industry. A title opinion is obtained prior to the commencement of any drilling operations on such properties. The Company's properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, none of which the Company believes materially interferes with the use of, or affect the value of, such properties. All of the Company's United States properties are also subject to the liens of the Banks.

Government Regulation

The Company's business is subject to certain federal, state and local laws and regulations relating to the exploration for and development, production and marketing of crude oil and natural gas, as well as environmental and safety matters. Such laws and regulations have generally become more stringent in recent years, often imposing greater liability on a larger number of potentially responsible parties. Because the requirements imposed by such laws and regulations are frequently changed, the Company is unable to predict the ultimate cost of compliance with such requirements. There is no assurance that laws and regulations enacted in the future will not adversely affect the Company's financial condition and results of operations.

Dependence on Key Personnel

The Company depends to a large extent on Robert L. G. Watson, its Chairman of the Board, President and Chief Executive Officer, for its management and business and financial contacts. The unavailability of Mr. Watson would have a materially adverse effect on the Company's business. The Company's success is also dependent upon its ability to employ and retain skilled technical personnel. While the Company has not to date experienced difficulties in employing or retaining such personnel, its failure to do so in the future could adversely affect its business. The Company has entered into employment agreements with Mr. Watson and each of the Company's vice presidents. The employment agreements terminate on December 31, 1997 except that the term may be extended for an additional year if by December 1 of the prior year neither the Company nor the officer has given notice that it does not wish to extend the term. Except in the event of a change in control, Mr. Watson's and each of the vice president's employment is terminable at will by the Company for any reason, without notice or cause.

Limitations on the Availability of the Company's Net Operating Loss Carryforwards

At December 31, 1996, the Company had, subject to the limitations discussed below, $17.5 million of net operating loss carryforwards for tax purposes, of which approximately $16.1 million are available for utilization without limitation. These loss carryforwards will expire from 2002 through 2010 if not utilized. As a result of the acquisition of certain partnership interests and crude oil and natural gas properties in 1990 and 1991, an ownership change under Section 382 of the Internal Revenue Code of 1986, as amended (Section 382), occurred in December 1991. Accordingly, it is expected that the use of net operating loss carryforwards generated prior to December 31, 1991 of $4.9 million will be limited to approximately $235,000 per year. During 1992 the Company acquired 100% of the outstanding capital stock of an unrelated corporation. The use of the net operating loss carryforwards of $1.1 million of the unrelated corporation are limited to approximately $115,000 per year. As a result of the issuance of additional shares of Common Stock for acquisitions and sales of stock, an additional ownership change under Section 382 occurred in October 1993. Accordingly, it is expected that the use of the $8.2 million of net operating loss carryforwards generated through October 1993 will be limited to approximately $1 million per year subject to the lower limitations described above and $7.2 million in the aggregate. Future changes in ownership may further limit the use of the Company's carryforwards. 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 $5.7 million and $5.7 million for deferred tax assets at December 31, 1996 and 1995, respectively.

Regulation of Crude Oil and Natural Gas Activities

Regulatory Matters

The Company's operations are affected from time to time in varying degrees by political developments and federal, state, provincial and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by 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 recent past, maximum selling prices for certain categories of crude oil, natural gas, condensate and NGLs were subject to federal regulation. In 1981, all federal price controls over sales of crude oil, condensate and NGLs were lifted. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") deregulated natural gas prices for all "first sales" of natural gas, which includes all sales by the Company of its own production. As a result, all sales of the Company's domestically produced crude oil, natural gas, condensate and NGLs may be sold at market prices, unless otherwise committed by contract.

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. As is the case with crude oil, 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 government of Alberta also regulates the volume of natural gas that may be removed from Alberta 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.

Natural Gas Regulation. Historically, interstate pipeline companies generally acted as wholesale merchants by purchasing natural gas from producers and reselling the gas to local distribution companies and large end users. Commencing in late 1985, the Federal Energy Regulatory Commission (the "FERC") issued a series of orders that have had a major impact on interstate natural gas pipeline operations, services, and rates, and thus have significantly altered the marketing and price of natural gas. The FERC's key rule making action, order No. 636 ("Order 636"), issued in April 1992, required 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 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 makes natural gas sales as a merchant, it does so pursuant to private contracts in direct competition with all of the sellers, such as the Company; however, pipeline companies and their affiliates were not required to remain "merchants" of natural gas, and most of the interstate pipeline companies have become "transporters only." In subsequent orders, the FERC largely affirmed the major features of Order 636 and denied a stay of the implementation of the new rules pending judicial review. By the end of 1994, the FERC had concluded the Order 636 restructuring proceedings, and, in general, accepted rate filings implementing Order 636 on every major interstate pipeline. However, even through the implementation of Order 636 on individual interstate pipelines is essentially complete, many of the individual pipeline restructuring proceedings, as well as Order 636 itself and the regulations promulgated thereunder, are subject to pending appellate review and could possibly be changed as a result of future court orders. The Company cannot predict whether the FERC's orders will be affirmed on appeal or what the effects will be on its business.

In recent years the FERC also has pursued a number of other important policy initiatives which could significantly affect the marketing of natural gas. Some of the more notable of these regulatory initiatives include (I) a series of orders in individual pipeline proceedings articulating a policy of generally approving the voluntary divestiture of interstate pipeline owned gathering facilities by interstate pipelines to their affiliates (the so-called "spin down" of previously regulated gathering facilities to the pipeline's nonregulated affiliates), (ii) the completion of rule-making involving the regulation of pipelines with marketing affiliates under Order No. 497, (iii) the FERC's ongoing efforts to promulgate standards for pipeline electronic bulletin boards and electronic data exchange, (iv) a generic inquiry into the pricing of interstate pipeline capacity, (v) efforts to refine the FERC's regulations controlling operation of the secondary market for released pipeline capacity, and (vi) a policy statement regarding market based rates and other non-cost-based rates for interstate pipeline transmission and storage capacity. Several of these initiatives are intended to enhance competition in natural gas markets, although some, such as "spin downs," may have the adverse effect of increasing the cost of doing business on some in the industry as a result of the monopolization of those facilities by their new, unregulated owners. The FERC has attempted to address some of these concerns in its orders authorizing such "spin downs," but it remains to be seen what effect these activities will have on access to markets and the cost to do business. As to all of these recent FERC initiatives, the ongoing, or, in some instances, preliminary evolving nature of these regulatory initiatives makes it impossible at this time to predict their ultimate impact on the Company's business.

Recent orders of the FERC have been 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 once classified as "transmission" may now be classified as "gathering." The Company transports certain of its natural gas through gathering facilities owned by others, including interstate pipelines, under existing long term contractual arrangements. With respect to item (i) in the preceding paragraph, on May 27, 1994, the FERC issued orders in the context of the "spin off" or "spin down" of interstate pipeline owned gathering facilities. A "spin off" is a FERC-approved sale of such facilities to a non-affiliate. A "spin down" is the transfer by the interstate pipeline of its gathering facilities to an affiliate. A number of spin offs and spindowns have been approved by the FERC and implemented. The FERC held that it retains jurisdiction over gathering provided by interstate pipelines, but that it generally does not have jurisdiction over pipeline gathering affiliates, except in the event of affiliate abuse (such as actions by the affiliate undermining open and nondiscriminatory access to the interstate pipeline). These orders require nondiscriminatory access for all sources of supply and prohibit the tying of pipeline transportation service to any service provided by the pipeline's gathering affiliate. On November 30, 1994, the FERC issued a series of rehearing orders largely affirming the May 27, 1994 orders. The FERC now requires interstate pipelines to not only seek authority under Section 7(b) of the Natural Gas Act of 1938 (the "NGA") to abandon certificated facilities, but also to seek authority under Section 4 of the NGA to terminate service from both certificated and uncertificated facilities. On December 31, 1994, an appeal was filed with the U.S. Court of Appeals for the D.C. Circuit to overturn three of the FERC's November 30, 1994, orders. The Company cannot predict what the ultimate effect of the FERC's orders pertaining to gathering will have on its production and marketing, or whether the Appellate Court will affirm the FERC's orders on these matters.

State and Other Regulation. All of the jurisdictions in which the Company owns producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including 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. The Company's 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 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 allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state 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 these regulations is to limit the amounts of crude oil and natural gas the Company can produce from its wells, and to limit the number of wells or the location at which the Company can drill.

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take requirements, but does not generally entail rate regulation. Natural gas gathering has received greater regulatory scrutiny at both the state and federal levels in the wake of the interstate pipeline restructuring under Order 636. For example, Oklahoma recently enacted a prohibition against discriminatory gathering rates and certain Texas regulatory officials have expressed interest in evaluating similar rules.

Royalty Matters

United States. By a letter dated May 3, 1993, directed to thousands of producers holding interests in federal leases, the United States Department of the Interior (the "DOI") announced its interpretation of existing federal leases to require the payment of royalties on past natural gas contract settlements which were entered into in the 1980s and 1990s to resolve, among other things, take-or-pay and minimum take claims by producers against pipelines and other buyers. The DOI's letter sets forth various theories of liability, all founded on the DOI's interpretation of the term "gross proceeds" as used in federal leases and pertinent federal regulations. In an effort to ascertain the amount of such potential royalties, the DOI sent a letter to producers on June 18, 1993, requiring producers to provide all data on all natural gas contract settlements, regardless of whether natural gas produced from federal leases were involved in the settlement. The Company received a copy of this information demand letter. In response to the DOI's action, in July 1993, various industry associations and others filed suit in the United States District Court for the Northern District of West Virginia seeking an injunction to prevent the collection of royalties on natural gas contract settlement amounts under the DOI's theories. The lawsuit, styled "Independent Petroleum Association v. Babbitt," was transferred to the United States District Court in Washington, D.C. On June 4, 1995, the Court issued a ruling in this case holding that royalties are payable to the United States on natural gas contract settlement proceeds in accordance with the Minerals Management Service's May 3, 1993, letter to producers. This ruling was appealed and is now pending in the D.C. Circuit Court of Appeals. The DOI's claim in a bankruptcy proceeding against a producer based upon an interstate pipeline's earlier buy-out of the producer's natural gas sale contract was rejected by the Federal Bankruptcy Court in Lexington, Kentucky, in a proceeding styled "Century Offshore Management Corp." While the facts of the Court's decision do not involve all of the DOI's theories, the Court found on those at issue that the DOI's theories were without legal merit, and the Court's reasoning suggests that the DOI's other claims are similarly deficient. This decision was upheld in the District Court and is now on appeal in the Sixth Circuit Court of Appeals. Because both the "Independent Petroleum Association v. Babbitt" and "Century Offshore Management Corp." decisions have been appealed, and because of the complex nature of the calculations necessary to determine potential additional royalty liability under the DOI's theories, it is impossible to predict what, if any, additional or different royalty obligation the DOI may assert or ultimately be entitled to recover with respect to any of the Company's prior natural gas contract settlements.

Canada. 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 preference 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 Canada, Alberta and Saskatchewan 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.

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 qualifying development wells that were spudded on or after November 1, 1991, and prior to August 1, 1993 (or spudded in August but licensed prior thereto) are eligible for a 12-month royalty exemption up to a maximum of CDN$400,000. Exploration wells spudded on or after November 1, 1991 and prior to April 1, 1992, or if drilled in northern Alberta or the Foothills area of Alberta prior to April 1, 1993, are entitled to a 24-month exemption to a maximum of CDN$1.0 million. A 24-month royalty reduction (up to December 31, 1996) is available for crude oil produced from qualifying horizontal extensions commenced prior to January 1, 1995. Crude oil produced from horizontal extensions commenced at least five years after the well was originally spudded may also qualify for a royalty reduction. Wells drilled prior to September 1, 1990, and reactivated between November 1, 1991 and October 1, 1992, having had

no production between September 1, 1990 and November 1, 1991, are entitled to a five year royalty exemption to a maximum of 4,000 cubic metres. An 8,000 cubic metres exemption is available to production from a well that has not produced for a 12-month period, if resuming production in October, November or December of 1992 or January of 1993, or for a 24-month period if resuming production after January 31, 1993. 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 $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 also introduced the Third Tier Royalty with a base rate of 10% and a rate cap of 25% from oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30% and for old oil a base rate of 10% and a rate cap of 35%.

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 exploratory gas wells spudded or deepened after July 1, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. 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 metre and 35% for prices above CDN $210 per cubic metre. 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.

Crude oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid to the provincial governments. The ARTC program provides a rebate on Crown royalties paid in respect of eligible producing properties.

The Government of Saskatchewan revised its fiscal regime for the oil and gas industry effective January 1, 1994. Some royalties on wells existing as of that date will remain unchanged and therefore subject to various periods of royalty/tax reduction. While a number of incentives were eliminated or reduced (such as incentives for vertical infill wells and lower cost horizontal wells), new incentive programs were initiated to encourage greater exploration and development activity in the province. The new fiscal regime provides an incentive to encourage the drilling of new vertical oil wells through a revised royalty/tax structure for new vertical oil wells and incremental production from new or expanded water flood projects. This "third tier" Crown royalty rate is price sensitive and varies between heavy and non-heavy oil (from a minimum of 10% for heavy oil at a base price to a maximum of 35% for non-heavy oil at a price above the base price). Previous time-based royalty/tax holidays applicable to vertically drilled oil wells have been replaced with volume-based royalty/tax reduction incentives in which a maximum royalty of 5% will apply to various volumes depending on the depth and nature of the well (up to 25,000 cubic metres of oil in the case of deep exploratory wells). The maximum royalty applicable to the first 12,000 cubic metres of oil has been increased from 5% to 10% for production from certain horizontal wells. In addition, royalty/tax holidays for deep horizontal oil wells have been replaced with a 25,000 cubic metres volume incentive (5% maximum royalty). Oil production from qualifying reactivated oil wells are subject to a maximum new royalty rate of 5% for the first five years following re-activation in the case of wells reactivated after 1993 and shut-in or suspended prior to January 1, 1993. With respect to qualifying exploratory natural gas wells, the first 25 million cubic metres of natural gas produced will be subject to an incentive maximum royalty rate of 5%.

Environmental Matters

The Company's operations are subject to numerous federal, state, and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment, including the Comprehensive Environment Response, Compensation, and Liability Act ("CERCLA"), also known as the "Federal Superfund Law." Such laws and regulations, among other things, impose absolute liability upon the lessee under a lease for the cost of clean up of pollution resulting from a lessee's operations, subject the lessee to liability for pollution damages, may require suspension or cessation of operations in affected areas, and impose restrictions on the injection of liquids into subsurface aquifers that may contaminate groundwater. The Company maintains insurance against costs of clean-up operations, but it's not fully insured against all such risks. A serious incident of pollution may, as it has in the past, also result in the DOI requiring lessees under federal leases to suspend or cease operation in the affected area. In addition, the recent trend toward stricter standards in environmental legislation and regulation may continue. For instance, legislation has been proposed in Congress from time to time that would reclassify certain crude oil and natural gas production wastes as "hazardous wastes" which would make the reclassified exploration and production wastes subject to much more stringent handling, disposal, and clean up requirements. If such legislation were to be enacted, it could have a significant impact on the Company's operating costs, as well as the crude oil and natural gas industry in general. State initiatives to further regulate the disposal of crude oil and natural gas wastes are also pending in certain states, and these various matters could have a similar impact on the Company.

The Company's Canadian operations are also subject to environmental regulation pursuant to local, provincial and federal legislation. Canadian environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain crude oil and natural gas industry operations and 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. Environmental legislation in Alberta has undergone a major revision and has been consolidated in the Environmental and Enhancement Act . Under the new Act, environmental standards and compliance for releases, clean-up and reporting are stricter. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have incremental effect on the cost of conducting operations in Alberta.

The Company is not currently involved in any administrative or judicial proceedings arising under domestic or foreign federal, state, or local environmental protection laws and regulations which would have a material adverse effect on the Company's financial position or results of operations.

Employees

As of March 21, 1997, Abraxas and its subsidiaries had 64 full-time employees, including two executive officers, four non-executive officers, four petroleum engineers, one landman, two geologists, 24 secretarial, accounting and clerical personnel and 27 field personnel. Additionally, Abraxas also retains contract pumpers on a month-to-month basis. Abraxas retains independent geologic, geophysical and engineering consultants from time to time on a limited basis and expects to continue to do so in the future.

Recent Activities

In January 1997, Canadian Abraxas sold its interest in the Hoole Area (the "Hoole Area") for approximately $9.3 million. The Hoole Area consists of 9,728 gross acres (3,311 net acres) and 6.0 gross wells (3.2 net wells), none of which are operated by Canadian Abraxas. As of January 1, 1997, the Hoole Area natural gas properties had total proved reserves of 1,268.0 MBOE with a Present Value of Proved Reserves of $11.2 million, all of which was attributable to proved developed reserves. The Hoole Area natural gas processing plant had aggregate net natural gas processing capacity of 32.0 MMCF per day at December 31, 1996. For the twelve months ended December 31, 1996, the Hoole Area natural gas processing plant processed an average of 18.9 gross MMCF (9.5 net MMCF) of natural gas per day, of which 4.4% (2.2% net) was custom processed for third parties.

Item 2. Properties.

Exploratory and Developmental Acreage

Abraxas' 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 Abraxas' interest in developed and undeveloped acreage as of December 31, 1996:

Developed and Undeveloped Acreage
As of December 31, 1996

State	Developed Acreage(1)		Undeveloped Acreage(2)	
	Gross Acres(3)	Net Acres(4)	Gross Acres(3)	Net Acres(4)
Canada	88,085(5)	47,140(5)	92,284	41,005
Texas	41,115	23,153	22,477	13,864
Wyoming	5,239	3,620	14,020	9,476
N. Dakota	1,864	1,021	--	--
Alabama	720	23	--	--
Kansas	640	142	--	--
Montana	320	10	--	--
New Mexico	320	42	--	--
TOTAL	138,303	75,151	128,781	64,345

(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 oil and gas, regardless of whether or not such acreage contains proved reserves.
(3) Gross acres refers to the number of acres in which Abraxas owns 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).
(5) Includes 9,728 gross acres and 3,311 net acres in the Hoole Area. See "Business - Recent Activities".

Productive Wells

The following table sets forth the total gross and net productive wells of Abraxas, expressed separately for crude oil and natural gas, as of December 31, 1996:

Productive Wells(1)

STATE/ COUNTRY	CRUDE OIL		NATURAL GAS	
	Gross(2)	Net(3)	Gross(2)	Net(3)
Texas	258.0	180.6	98.0	63.6
Canada(4)	15.0	12.5	132.0	55.2(4)
Kansas	4.0	0.8	--	--
N. Dakota	4.0	1.7	--	--
Alabama	2.0	0.1	1.0	0.1
Montana	1.0	0.1	--	--
Wyoming	1.0	0.1	29.0	21.3
New Mexico	--	--	1.0	0.1
TOTAL	285.0	195.9	261.0	140.3

(1) Productive wells are producing wells and wells capable of production.

(2) A gross well is a well in which Abraxas owns a working interest. The number of gross wells is the total number of wells in which Abraxas owns a working 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 Abraxas' fractional working interest owned in gross wells.
(4) Includes 6.0 gross wells and 3.2 net wells in the Hoole Area. See "Business - Recent Activities".

Substantially all of Abraxas' existing crude oil and natural gas properties are pledged to secure Abraxas' indebtedness under its' credit agreement. See "Management's Discussion of Financial Condition and Results of Operations--Liquidity and Capital Resources".

Reserves Information

The crude oil and natural gas reserves of Abraxas have been estimated as of January 1, 1997, January 1, 1996 and January 1, 1995 and of Canadian Abraxas as of January 1, 1997, by DeGolyer & MacNaughton, of Dallas, Texas. Crude oil and natural gas reserves, and the estimates of the present value of future net revenues therefrom, were determined based on then current prices and costs. Reserve calculations involved 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 therefrom. 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 Abraxas' crude oil, natural gas liquids and natural gas reserves as of January 1, 1997, January 1, 1996 and January 1, 1995.

	ESTIMATED PROVED RESERVES		
	Proved Developed	Proved Undeveloped	Total Proved
As of January 1, 1995			
Crude Oil, Bbls	3,616,510	3,032,818	6,649,328
Natural Gas Liquids, Bbls	2,089,168	417,994	2,507,162
Natural Gas, Mcf	48,973,212	18,605,881	67,579,093
As of January 1, 1996			
Crude Oil, Bbls	3,991,804	1,516,012	5,507,816
Natural Gas Liquids, Bbls	2,007,777	751,649	2,759,426
Natural Gas, Mcf	44,025,782	10,542,825	54,568,607
As of January 1, 1997 (1)			
Crude Oil, Bbls	7,871,308(2)	1,930,240	9,801,548(2)
Natural Gas Liquids, Bbls	7,089,755	1,144,341	8,234,096
Natural Gas, Mcf	157,660,157	19,599,554	177,259,711

(1) Includes reserves of Canadian Abraxas (Including 1,268 MBOE attributable to the Hoole Area).

(2) Includes 120,400 barrels of crude oil reserves owned by Cascade of which 57,600 barrels are applicable to the minority interest's share of the reserves.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their estimated values, including many factors beyond the control of the producer. The reserve data set forth herein represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgement. As a result, estimates of different engineers often vary. In addition, estimates of reserves are subject to revision by the results of drilling, testing and production subsequent to the date of such estimates. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based.

In general, the volume of production from crude oil and natural gas properties declines as reserves are depleted. Except to the extent the Company acquires properties containing proved reserves or conducts successful exploration and development activities, or both, the proved reserves of the Company will decline as reserves are produced. The Company's future crude oil and natural gas production is therefore highly dependent upon its level of success in acquiring or finding additional reserves.

The Company files reports of its 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 the net crude oil, net natural gas liquids and net natural gas production for Abraxas, 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, 1996:

	1996	1995	1994
Crude oil production (Bbls)	425,188	401,445	355,710
Natural gas production (Mcf)	6,350,069	3,552,671	2,392,855
Natural gas liquids Production (Bbls)	299,509	143,380	113,157
Average sales price per Bbl of crude oil($)	$20.85	$17.16	$15.47
Average sales price per Mcf of natural gas($)	$1.97	$1.47	$1.85
Average sales price per Bbl. of natural gas liquids	$14.55	$10.83	$10.54
Average cost of production ($) per BOE produced (1)	$3.28	$3.81	$4.26

(1) Oil and gas were combined by converting gas to a barrel oil equivalent ("BOE") on the basis of 6 Mcf gas =1 Bbl of oil. Production costs include direct operating costs, ad valorem taxes and gross production taxes.

Drilling Activities

The following table sets forth Abraxas' gross and net working interests in exploratory, development, and service wells drilled during the three years ended December 31, 1996:

	1996		1995		1994	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Exploratory(3)	-	-	-	-	-	-
Productive(4)	-	-	-	-	-	-
Crude oil	2.0	1.2	1	.72	-	-
Natural gas	2.0	1.2	-	-	1	2
Dry holes(5)	4.0	1.4	1	1	2	5
Total	8.0	3.8	2	1.72	3	7
Development(6)						
Productive			-	-	-	-
Crude oil	20.0	15.8	12	9.1	3	1.5
Natural gas	10.0	3.7	2	.6	6	2.1
Service(7)	1.0	1.0	-	-	-	-
Dry holes(5)	-	-	1	.3	-	-
Total	31.0	20.5	15	10.0	9	3.6

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(1) A gross well is a well in which Abraxas owns 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.

(7) A service well is used for water injection in secondary recovery projects or for the disposal of produced water.

Office Facilities

The Company's executive and administrative offices are located at 500 N. Loop 1604 East, Suite 100, San Antonio, Texas 78232. The Company owns a 16% limited partnership interest in the Partnership which owns the office building. The Company also has an office in Midland, Texas. These offices, consisting of approximately 12,650 square feet in San Antonio and 960 square feet in Midland, are leased until March 2006 from unaffiliated parties at an aggregate rate of $13,166 per month.

Other Properties

The Company owns 10 acres of land, an office building, shop, warehouse and house in Sinton, Texas, 160 acres of land in Coke County, Texas and a 50% interest in approximately 2.0 acres of land in Bexar County, Texas. All three properties are used for the storage of tubulars and production equipment. The Company also owns 20 vehicles which are used in the field by employees.

Item 3. Legal Proceedings

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. As of March 21, 1997, 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.

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

No matter was submitted to a vote of security holders of the Company during the fourth quarter of the fiscal year ended December 31, 1996.

Item 4a. Executive Officers of the Company

Certain information is set forth below concerning the executive officers of the Company, each of whom has been selected to serve until the 1997 annual meeting of directors and until his successor is duly elected and qualified.

Robert L. G. Watson, age 46, has served as President and a director of the Company since 1977. Prior to joining the Company, Mr. Watson was employed in various petroleum engineering positions. From 1970 to 1972, Mr. Watson was employed by DeGolyer & MacNaughton, an independent petroleum engineering firm and from 1972 through 1977, Mr. Watson was employed by Tesoro Petroleum Corporation, a crude oil and natural gas exploration and production company. Mr. Watson received the degree of Bachelor of Science in Mechanical Engineering from Southern Methodist University in 1972 and Master of Business Administration from the University of Texas at San Antonio in 1974.

Chris E. Williford, age 45, was elected Vice President, Treasurer and Chief Financial Officer of the Company in January 1993, and as Executive Vice President and a director of the Company in May 1993. Prior to joining the Company, Mr. Williford was Chief Financial Officer of American Natural Energy Corporation, a crude oil and natural gas exploration and production company, from July 1989 to December 1992 and President of Clark Resources Corp., a crude oil and natural gas exploration and production company, from January 1987 to May 1989. Mr. Williford received a degree of Bachelor of Science in Business Administration from Pittsburg State University in 1973.

PART II

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

Market Information

Abraxas Common Stock is traded on the NASDAQ Stock Market and commenced trading on May 7, 1991. The following table sets forth certain information as to the high and low bid quotations quoted on NASDAQ for 1994, 1995 and 1996. Information with respect to over-the-counter bid quotations represents prices between dealers, does not include retail mark-ups, mark-downs or commissions, and may not necessarily represent actual transactions.

	Period	High	Low
1994			
	First Quarter	$13.50	$9.00
	Second Quarter	13.50	9.75
	Third Quarter	13.13	9.00
	Fourth Quarter	11.50	9.25
1995			
	First Quarter	$10.25	$8.50
	Second Quarter	9.63	8.00
	Third Quarter	8.88	7.94
	Fourth Quarter	8.88	6.13
1996			
	First Quarter	$7.75	$4.13
	Second Quarter	7.25	5.00
	Third Quarter	7.13	4.75
	Fourth Quarter	10.50	5.75

Holders

As of March 21, 1997 Abraxas had 5,732,101 shares of common stock outstanding and had approximately 1,900 Stockholders of record.

Dividends

Abraxas has not paid any cash dividends on its Common Stock and it is not presently determinable when, if ever, Abraxas will pay cash dividends in the future. The Credit Agreement and the Indenture, prohibits the payment of cash dividends and stock dividends on the Company's Common Stock. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources".

Item 6. Selected Financial Data

The following selected financial data are derived from the consolidated financial statements of Abraxas. The data should be read in conjunction with the consolidated financial statements, related notes, and other financial information included herein.

	Year Ended December 31,				
	1996	1995	1994	1993	1992
	(In thousands, except per share data)				
Total revenue	$ 26,653	$13,817	$11,349	$ 7,494	$ 2,691
Income (loss) from continuing operations	$ 1,940	$(1,209)	$ 113	$(1,580)	$(1,072)
Income (loss) per common share and common equivalent from continuing operations	$ .23	$ (.34)	$ .02	$ (.91)	$ (1.23)
Weighted average shares outstanding	6,794	4,635	4,310	1,947	1,074
Total Assets	$304,842	$85,067	$75,361	$43,396	$18,017
Long-term debt	$215,032	$41,601	$41,296	$12,529	$ 6,602
Total shareholders' equity	$ 35,656	$37,062	$28,502	$25,143	$ 2,233

Item 7. Management's Discussion And Analysis Of Financial Condition And Results Of Operations

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

Results of Operations

The factors which most significantly affect the Company's results of operations are (1) the sales prices of crude oil, natural gas liquids and natural gas, (2) the level of total sales volumes of crude oil, natural gas liquids and natural gas, (3) the level of and interest rates on borrowings and (4) the level and success of exploration and development activity.

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

	Years Ended December 31		
	1996	1995	1994
Operating revenue (in thousands):			
Natural gas sales....................	$12,526	$6,889	$5,501
Crude oil sales.......................	8,864	5,218	4,420
Natural gas liquid sales.............	4,359	1,553	1,193
Gas Processing Revenue................	600	--	--
Other.................................	304	157	235
Total operating revenue...............	$26,653	$13,817	$11,349
Operating income (loss) in thousands...	$8,826	$2,883	$2,923
Natural gas production (Mmcfs)..........	6,350.0	3,552.7	2,392.9
Crude oil production (Mbbls)............	425.2	401.4	355.7
Natural gas liquids production (Mbbls)..	299.5	143.4	113.2
Average natural gas sales price ($/Mcf).	$1.97	$1.47	$1.85
Average crude oil sales price ($/Bbl)...	$20.85	$17.16	$15.47
Average natural gas liquids sales price ($/Bbl)..............................	$14.55	$10.83	$10.54

Comparison of Year Ended December 31, 1996 to Year Ended December 31, 1995

Operating Revenue. During the year ended December 31, 1996, operating revenue from crude oil, natural gas and natural gas liquids sales, and natural gas processing revenues increased 92% from $13.7 million in 1995 to $26.3 million. This increase was primarily attributable to increased crude oil and natural gas liquids sales volumes of 33.0% and natural gas sales volumes of 78.7% which was attributable to increased production from the producing properties that the Company owned for the entire year as well as producing properties acquired during the year. This increase more than offset the loss of operating revenue from the Portilla and Happy fields during the portion of the year that the Company did not own the properties. During 1995, the Portilla and Happy Fields contributed $4.6 million in operating revenue compared to $2.0 million in 1996. Crude oil and NGLs sales volumes increased from 545 MBbls to 725 MBbls, from 1995 to 1996 and natural gas sales volumes increased from 3.6 BCF to 6.4 BCF, from 1995 to 1996 as a result of increased production volumes from the Company's properties other than Portilla and Happy in 1996 as compared to 1995 and the acquisitions of the Wyoming Properties, the stock of CGGS and the Company's ongoing development drilling program. Portilla and Happy contributed 226.0 MBbls of crude oil and NGLs (41.5% of Company total) and 492.6 MMcf of natural gas (13.9% of Company total) during 1995 as compared to 91.7 MBbls of crude oil and NGLs (12.7% of Company total) and 215.6 MMcf of natural gas (3.4% of Company total) for 1996. Average sales prices were $20.85 per Bbl of crude oil, $14.55 per Bbl of natural gas liquids and $1.97 per Mcf of natural gas for the year ended December 31, 1996 compared with $17.16 per Bbl of crude oil, $10.83 per Bbl of natural gas liquid and $1.47 per MMcf of natural gas for the year ended December 31, 1995. A general strengthening of crude oil and natural gas prices at the wellhead during 1996 resulted in a higher average sales prices received by the Company during the year ended December 31, 1996 compared to the same period in 1995.

Lease Operating Expenses. Lease operating expenses and natural gas processing costs ("LOE"), increased by 41.2% from $4.3 million for the year ended December 31, 1995 to $6.1 million for the same period of 1996, primarily due to the greater number of wells owned by the Company for the year ended December 31, 1996 compared to the year ended December 31, 1995. The Company's LOE on a per BOE basis for 1996 was $3.28 per BOE as compared to $3.81 per BOE in 1995.

G & A Expenses. General and administrative expenses increased 85.5% from $1.0 million for the year ended December 31, 1995, to $1.9 million for the year ended December 31, 1996, as a result of the Company's hiring additional staff, including establishment of a Canadian administrative office, to manage the additional properties acquired by the Company and subsequent development of those properties. The Company's G & A expense on a per BOE basis was $1.08 per BOE in 1996 compared to $0.92 per BOE for 1995.

DD & A Expenses. Due to the increase in sales volumes of crude oil and natural gas, depreciation, depletion and amortization expense increased 76.8% from $5.4 million for the year ended December 31, 1995 to $9.6 million for the year ended December 31, 1996. The Company's DD&A expense on a per BOE basis for 1996 was $5.38 per BOE as compared to $4.78 per BOE in 1995.

Interest Expense and Preferred Dividends. Interest expense and preferred dividends increased 54.5%, from $4.3 million to $6.6 million for the year end December 31, 1996, compared to the 1995 period. This increase is attributable to increased borrowings by the Company to finance the acquisitions consumated during 1996. Long-term debt increased from $41.6 million at December 31, 1995 to $215.0 million at December 31, 1996.

Comparison of Year Ended December 31, 1995 to Year Ended December 31, 1994

Operating Revenue. During the year ended December 31, 1995, operating revenue from crude oil, natural gas and natural gas liquids sales increased by 22.9% from $11.1 million in 1994 to $13.7 million. This increase was primarily attributable to an increase in crude oil and natural gas liquids sales volumes of 16% and natural gas sales volumes of 48%. The increases in sales volumes of crude oil, natural gas liquids and natural gas from 1994 to 1995 were primarily a result of the acquisition of 80% of the overriding royalty interest previously granted to a lender (the "ORRI") and the West Texas Properties by the Company in June 1994 and July 1994 respectively, and the Company's ongoing development drilling program. Average sales prices were $17.16 per Bbl of crude oil, $10.83 per Bbl of natural gas liquids and $1.47 per Mcf of natural gas for the year ended December 31, 1995 compared with $15.47 per Bbl of crude oil, $10.54 per

Bbl of natural gas liquid and $1.85 per Mcf of natural gas for the year ended December 31, 1994. A general weakening of natural gas prices at the wellhead during the first nine months of 1995 resulted in a lower average natural gas sales price received by the Company during the year ended December 31, 1995 compared to the same period in 1994. This decrease was partially offset by an increase in crude oil prices received by the Company in 1995 as compared to 1994.

Lease Operating Expenses. LOE increased 17.3% from $3.7 million for the year ended December 31, 1994 to $4.3 million for the same period of 1995, primarily due to the greater number of wells owned by the Company during the year ended December 31, 1995 compared to the year ended December 31, 1994. The Company's LOE on a per BOE basis for the year ended December 31, 1994 was $4.26 per BOE as compared to $3.81 per BOE for the year ended December 31, 1995.

G & A Expenses. G & A expenses increased by 28.6%, from $810,000 to $1.0 million, from the year ended December 31, 1994 to the year ended December 31, 1995 as a result of hiring additional staff to manage and develop the West Texas Properties. The Company's G & A expenses on a per BOE basis for the year ended December 31, 1994 were $0.93 per BOE as compared to $0.92 per BOE for the year ended December 31, 1995.

DD & A Expenses. Due to the increase in sales volumes of crude oil and natural gas, depreciation, depletion and amortization expense increased 43.4% from $3.8 million for the year ended December 31, 1994 to $5.4 million for the year ended December 31, 1995. The Company's DD&A expenses on a per BOE basis for the year ended December 31, 1994 was $4.37 per BOE compared to $4.78 per BOE in 1995.

Interest Expenses and Preferred Dividends. As a result of the Company's borrowing $28 million to acquire the West Texas Properties in July 1994, interest expense increased 62.5% from $2.4 million in 1994 to $3.9 million in 1995. Long term debt increased from $41.3 million at December 31, 1994 to $41.6 million at December 31, 1995.

The Company has incurred operating losses and net losses for a number of years. The Company's revenues, profitability and future rate of growth are substantially dependent upon prevailing prices for crude oil and natural gas and the volumes of crude oil, natural gas and natural gas liquids produced by the Company. Natural gas prices increased substantially during 1996. For the year ended December 31, 1996 average natural gas prices realized by the Company were $1.97 per Mcf compared with $1.47 per Mcf at December 31, 1995 and $1.85 per Mcf at December 31, 1994. Although the Company had operating and net income during 1996, there can be no assurance that operating income and net earnings will be achieved in future periods. At December 31, 1996, U.S. crude oil prices were $23.55 per Bbl compared to $18.13 at December 31, 1995 and $15.59 per Bbl at December 31, 1994. In addition, because the Company's proved reserves will decline as crude oil, natural gas and natural gas liquids are produced, unless the Company is successful in acquiring properties containing proved reserves or conducts successful exploration and development activities, the Company's reserves and production will decrease. In the event natural gas prices return to depressed levels or if crude oil prices begin to decrease, or if the Company's production levels decrease, the Company's revenues, cash flow from operations and profitability will be materially adversely affected.

Liquidity and Capital Resources

Capital expenditures in 1994, 1995 and 1996 were $40.9 million, $9.7 million and $172.9 million, respectively. The table below sets forth the components of these capital expenditures on a historical basis for the three years ended December 31, 1994, 1995 and 1996.

	Year Ended December 31 (In thousands) 1996	1995	1994
Expenditure category:			
Property acquisition (1)	$154,484	$ 719	$33,709
(Divestitures)	(242)	(2,556)	(70)
Development	18,465	11,472	7,151
Facilities and other	206	139	158
Total	$172,913	$ 9,774	$40,948

(1) Acquisition costs includes 45,741 shares of Preferred Stock valued at $4.6 million in 1994.

Acquisitions of crude oil and natural gas producing properties beginning during 1991 and continuing through the year ended December 31, 1996 account for the majority of the capital expenditures made by the Company since January 1, 1991. These expenditures were funded through internally generated cash flow, borrowings from the Company's previous lenders and the Banks, the issuance of shares of the Company's Common and Preferred Stock to property sellers and the issuance of the Senior Notes.

At December 31, 1996, the Company had current assets of $23.3 million and current liabilities of $16.9 million resulting in working capital of $6.4 million. This compares to working capital of $2.6 million at December 31, 1995. The material components of the Company's current liabilities at December 31, 1996 include trade accounts payable of $10.0 million, revenues due third parties of $2.4 million and accrued interest of $3.2 million. Shareholders' equity decreased from $37.1 million at December 31, 1995 to $35.7 million at December 31, 1996 primarily due to an unrealized foreign currency translation adjustment of $2.4 million.

The Company's current budget for capital expenditures for 1997 other than acquisition expenditures is $35.2 million. Such expenditures will be made primarily for the development of existing properties. Additional capital expenditures may be made for acquisition of producing properties if such opportunities arise, but the Company currently has no agreements, arrangements or undertakings regarding any material acquisitions. The Company has no material long-term capital commitments and is consequently able to adjust the level of its expenditures as circumstances dictate. Additionally, the level of capital expenditures will vary during future periods depending on market conditions and other related economic factors.

On November 14, 1996, Abraxas and Canadian Abraxas consummated the offering of $215 million of the Notes. Interest on the Notes accrues from their date of original issuance (the "Issue Date") and is payable semi-annually in arrears on May 1 and November 1 of each year, commencing on May 1, 1997, at the rate of 11.5% per annum. The Notes are redeemable, in whole or in part, at the option of Abraxas and Canadian Abraxas, on or after November 1, 2000, at the redemption prices set forth below, plus accrued and unpaid interest to the date of redemption, if redeemed during the 12-month period commencing on November 1 of the years set forth below:

Year	Percentage
2000	105.75%
2001	102.875%
2002 and thereafter	100%

In addition, at any time on or prior to November 1, 1999, Abraxas and Canadian Abraxas may, at their option, redeem up to 35% of the aggregate principal amount of the Notes originally issued with the net cash proceeds of one or more equity offerings, at a redemption price equal to 111.5% of the aggregate principal amount of the Notes to be redeemed, plus accrued and unpaid interest to the date of redemption; provided, however, that after giving effect to any such redemption, at least $139.75 million aggregate principal amount of the Notes remains outstanding.

The Notes are joint and several obligations of Abraxas and Canadian Abraxas, and rank pari passu in right of payment to all existing and future unsubordinated indebtedness of Abraxas and Canadian Abraxas. The Notes rank senior in right of payment to all future subordinated indebtedness of Abraxas and Canadian Abraxas. The Notes are, however, effectively subordinated to secured indebtedness of Abraxas and Canadian Abraxas to the extent of the value of the assets securing such indebtedness.

The Notes are unconditionally guaranteed, jointly and severally, by certain of Abraxas' and Canadian Abraxas' future subsidiaries (the "Subsidiary Guarantors"). The guarantees are general unsecured obligations of the Subsidiary Guarantors and rank pari passu in right of payment to all unsubordinated indebtedness of the Subsidiary Guarantors and senior in right of payment to all subordinated indebtedness of the Subsidiary Guarantors. The Guarantees are effectively subordinated to secured indebtedness of the Subsidiary Guarantors to the extent of the value of the assets securing such indebtedness. As of December 31, 1996, Abraxas, Canadian Abraxas and the Subsidiary Guarantors had no secured indebtedness outstanding.

Upon a Change of Control (as defined in the Indenture governing the Notes), each holder of the Notes will have the right to require Abraxas and Canadian Abraxas to repurchase all or a portion of such holder's Notes at a redemption price equal to 101% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase. In addition, Abraxas and Canadian Abraxas will be obligated to offer to repurchase the Notes at 100% of the principal amount thereof plus accrued and unpaid interest to the date of repurchase in the event of certain asset sales.

The net proceeds to Abraxas and Canadian Abraxas from the offering of the Notes were approximately $207.0 million after deducting underwriting discounts and estimated offering expenses payable by Abraxas and Canadian Abraxas. Abraxas and Canadian Abraxas used the net proceeds to (i) repay all amounts outstanding under its bridge facility dated September 30, 1996 with Bankers Trust Company ("BT") and other lenders in the amount of $85.0 million, (ii) acquire the outstanding capital stock of CGGS for $94.7 million, (iii) acquire the Portilla and Happy properties and repay certain indebtedness for $27.5 million and (iv) provide working capital for general corporate purposes including future acquisitions and development of producing properties.

After consummation of the Offering and application of the net proceeds therefrom, the Company increased its total outstanding debt to approximately $215.1 million. In addition, on November 14, 1996, the Company entered into the Credit Facility concurrently with the consummation of the Offering. The Credit Facility provides for a revolving line of credit with an initial availability of $20.0 million, subject to certain customary conditions including a borrowing base condition.

Commitments available under the Credit Facility are subject to borrowing base redeterminations to be performed semi-annually and, at the option of each of the Company and the Banks, one additional time per year. Any outstanding principal balance in excess of the borrowing base will be due and payable in three equal monthly payments after a borrowing base redetermination. The borrowing base will be determined in BT's sole discretion, subject to the approval of the Banks, based on the value of the Company's reserves as set forth in the reserve report of the Company's independent petroleum engineers, with consideration given to other assets and liabilities.

The Credit Facility has an initial revolving term of two years and a reducing period of three years from the end of the initial two-year period. The commitment under the Credit Facility will be reduced during such reducing period by eleven equal quarterly reductions. Quarterly reductions will equal 8.2% per quarter with the remainder due at the end of the three-year reducing period.

The applicable interest rate charged on the outstanding balance of the Credit Facility is based on a facility usage grid. If the borrowings under the Credit Facility represent an amount less than or equal to 33.3% of the available borrowing base, then the applicable interest rate charged on the outstanding balance will be either (a) an adjusted rate of the London Inter-Bank Offered Rate ("LIBOR") plus 1.25% or (b) the prime rate of BT (which is based on BT's published prime rate) plus 0.50%. If the borrowings under the Credit Facility represent an amount greater than or equal to 33.3% but less than 66.7% of the available borrowing base, then the applicable interest rate on the outstanding principal will be either (a) LIBOR plus 1.75% or (b) the prime rate of BT plus 0.50%. If the borrowings under the Credit Facility represent an amount greater than or equal to 66.7% of the available borrowing base, then the applicable interest rate on the outstanding principal will be either (a) LIBOR plus 2.00% or (b) the prime rate of BT plus 0.50%. LIBOR elections can be made for periods of one, three or six months.

The Credit Facility contains a number of covenants that, among other things, restrict the ability of the Company to (i) incur certain indebtedness or guarantee obligations, (ii) prepay other indebtedness including the Notes, (iii) make investments, loans or advances, (iv) create certain liens, (v) make certain payments, dividends and distributions, (vi) merge with or sell assets to another person or liquidate, (vii) sell or discount receivables, (viii) engage in certain intercompany transactions and transactions with affiliates, (ix) change its business, (x) experience a change of control and (xi) make amendments to its charter, by-laws and other debt instruments. In addition, under the Credit Facility, the Company is required to comply with specified financial ratios and tests, including minimum debt service coverage ratios, maximum funded debt to EBITDA tests, minimum net worth tests and minimum working capital tests.

The Credit Facility contains customary events of default, including nonpayment of principal, interest or fees, violation 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 and change of control. The Indenture also contains a number of covenants and events of default including covenants restricting, among other things, the Company's 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 the assets of the Company and events of default including nonpayment of principal or interest on the Notes, violation of covenants, cross default on other indebtedness, bankruptcy and material judgments.

The Indenture also provides that the Company may not, and may not cause or permit certain of its subsidiaries, including Canadian Abraxas, to, directly or indirectly, create or otherwise cause to permit to exist or become effective any encumbrance or restriction on the ability of such subsidiary to pay dividends or make distributions on or in respect of its capital stock, make loans or advances or pay debts owed to Abraxas, guarantee any indebtedness of Abraxas or transfer any of its assets to Abraxas except for such encumbrances or restrictions existing under or by reason of: (I) applicable law; (ii) the Indenture; (iii) the Credit Facility; (iv) customary non-assignment provisions of any contract or any lease governing leasehold interests of such subsidiaries; (v) any instrument governing indebtedness assumed by the Company in an acquisition, which encumbrance or restriction is not applicable to such subsidiaries or the properties or assets of such subsidiaries other than the entity or the properties or assets of the entity so acquired; (vi) customary restrictions with respect to subsidiaries of the Company pursuant to an agreement that has been entered in to for the sale or disposition of capital stock or assets of such subsidiaries to be consummated in accordance with the terms of the Indenture solely in respect of the assets or capital stock to be sold or disposed of; (vii) any instrument governing certain liens permitted by the Indenture, to the extent and only to the extent such instrument restricts the transfer or other disposition of assets subject to such lien; or (viii) an agreement governing indebtedness incurred to refinance the indebtedness issued, assumed or incurred pursuant to an agreement referred to in clause (ii), (iii) or (v) above; provided, however, that the provisions relating to such encumbrance or restriction contained in any such refinancing indebtedness are no less favorable to the holders of the Notes in any material respect as determined by the Board of Directors of the Company in their reasonable and good faith judgement than the provisions relating to such encumbrance or restriction contained in the applicable agreement referred to in such clause (ii), (iii) or (v).

In August 1995, the Company entered into a rate swap agreement with a previous lender relating to $25.0 million of principal amount of outstanding indebtedness. This agreement was assumed by the Banks in connection with a bridge facility that was subsequently paid off. Under the agreement, the Company pays a fixed rate of 6.15% while the Banks in l pay a floating rate equal to the USD-LIBOR-BBA rate for one month maturities, quoted on the eighteenth day of each month, to the Company. Settlements are due monthly. The agreement terminates in August 1998. At December 31, 1996, the fair value of this swap, as determined by BT CO was approximately $200,000 and was recorded as interest expense at December 31, 1996.

In connection with the re-acquisition of the Portilla and Happy Fields, the Company assumed a commodity price hedge on variable volumes of crude oil and natural gas. Monthly settlements with amounts either due to or from Christiania are based on the differential between a fixed and a variable price for crude oil and natural gas. During 1997, the approximate monthly volume of crude oil sales subject to this agreement is 15,800 barrels at a fixed price of $17.20. This agreement reduces to approximately 13,200 barrels per month in 1998, 11,000 barrels per month in 1999, 9,100 barrels per month in 2000 and 8,200 barrels per month in 2001 until November 1. The fixed price paid to the Company over this five year period averages $17.55 per barrel. The natural gas component of this agreement calls for approximately 54,000 MMBTU per month at a fixed price of $1.80 during 1997 with volumes decreasing to 37,000 MMBTU per month in 1998, 24,000 MMBTU per month in 1999, 19,000 MMBTU per month in 2000 and 15,000 MMBTU per month in 2001 through October. The fixed price paid to the Company over this five year period averages $1.84 per MMBTU.

The Company has also entered into two fixed price agreements, each relating to approximately 3,750 net Mcf per day of natural gas. The first of these two expires on March 31, 1997 and calls for a fixed price of $1.52 per MMBTU being paid to the Company. The second agreement expires on October 31, 1997 and provides a fixed price of $1.42 per MMBTU to the Company.

The Company has also recently entered into a costless collar relating to 1,000 barrels a day of oil sales for the period February 1, 1997 through December 31, 1997. This agreement guarantees a minimum price of $19.00 per barrel to the Company and provides that any amount above $25.60 per barrel be remitted by the Company to the counterparty to the agreement.

Operating activities for the year ended December 31, 1996 provided $13.5 million of cash to the Company. Investing activities required $172.6 million during 1996 primarily for the acquisition of the Wyoming Properties, CGGS and the Portilla and Happy Fields. Financing provided $163.0 million during 1996.

For the year ended December 31, 1995, operating activities provided $4.5 million of cash. Investing activities required $10.1 million primarily for the development of existing properties. Total cash provided from financing activities for 1995 was $9.8 million as the result of the sale of 1,330,000 shares of Common Stock and contingent value rights during November 1995 which resulted in net proceeds of $10.1 million.

During 1994, operating activities provided $4.4 million of cash. Investing activities during 1994 utilized $36.0 million of cash primarily for the acquisition of the ORRI and the West Texas Properties for $29.0 million and the development of producing properties of $7.2 million. The Company borrowed $40.9 million during 1994, repaid $12.7 million of long term debt, sold Common Stock for proceeds of $1.5 million and paid financing fees and dividends on preferred stock resulting in a net contribution of $29.2 million from financing activities.

The Company is heavily dependent on crude oil and natural gas prices which have historically been volatile. Although the Company has hedged a portion of its natural gas production and intends to continue this practice, future crude oil and natural gas price declines would have a negative impact on the Company's overall results, and therefore, its liquidity. Furthermore, low crude oil and natural gas prices could affect the Company's ability to raise capital on terms favorable to the Company.

At December 31, 1996, the Company had, subject to the limitations discussed below, $20.1 million of net operating loss carryforwards for U.S. tax purposes, of which approximately $17.5 million are available for utilization without limitation. These loss carryforwards will expire from 2002 through 2010 if not utilized. At December 31, 1996, the company had approximately $830,000 of net operating loss carryforwards for Canadian tax purposes which expire in 2003. As a result of the acquisition of certain partnership interests and crude oil and natural gas properties in 1990 and 1991, an ownership change under Section 382 of the Internal Revenue Code of 1986, as amended (Section 382), occurred in December 1991. Accordingly, it is expected that the use of net operating loss carryforwards generated prior to December 31, 1991 of $4.9 million will be limited to approximately $235, 000 per year. As a result of the issuance of additional shares of Common Stock for acquisitions and sales of stock, an additional ownership change under Section 382 occurred in October 1993. Accordingly, it is expected that the use of all U.S. net operating loss carryforwards generated through October 1993 or $8.2 million will be limited to approximately $1 million per year subject to the lower limitations described above. Of the $8.2 million net operating loss carryforwards, it is anticipated that the maximum net operating loss that may be utilized before it expires is

$7.2 million. Future changes in ownership may further limit the use of the Company's carryforwards. 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 $5.7 million and $5.7 million for deferred tax assets at December 31, 1996 and 1995, respectively.

Based upon the current level of operations, the Company believes that cash flow from operations and the Company's Credit Facility with The Banks, will be adequate to meet its anticipated requirements for working capital, capital expenditures and scheduled interest payments through 1997. A depressed price for natural gas or crude oil will have a material adverse effect on the Company's cash flow from operations and anticipated levels of working capital, and could force the Company to revise its planned capital expenditures.

Disclosure Regarding Forward-Looking Information

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. All statements other than statements of historical facts included in this report regarding the Company's financial position, business strategy, budgets, reserve estimates, development and exploitation opportunities and projects, behind pipe zones, classification of reserves, projected costs, potential reserves, and plans and objectives of management for future operations including, but not limited to, statements including, any of the terms "anticipates", "expects", "estimates", "believes" and similar terms are forward-looking statements. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company's expectations ("Cautionary Statements") are disclosed under "Risk Factors" and elsewhere in this report including, without limitation, in conjunction with the forward-looking statements included in this report. All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressed qualified in their entirety by the Cautionary Statements.

Item 8. Financial Statements.

For the financial statements and supplementary data required by this Item 8, see the Index to Consolidated Financial Statements and Schedules.

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

Not Applicable.

PART III

Item 10. Directors and Executive Officers of the Registrant.

There is incorporated in this Item 10 by reference that portion of the Company's definitive proxy statement for the 199 annual meeting of shareholders which appears therein under the caption "Election of Directors". See also the information in Item 4a of Part I of this Report.

Item 11. Executive Compensation.

There is incorporated in this Item 11 by reference that portion of the Company's definitive proxy statement for the 1997 annual meeting of shareholders which appears therein under the caption "Executive Compensation", except for those parts under the captions "Compensation Committee Report on Executive Compensation", "Report on Repricing Options" and "Performance Graph".

Item 12. Security Ownership of Certain Beneficial Owners and Management.

There is incorporated in this Item 12 by reference that portion of the Company's definitive proxy statement for the 1997 annual meeting of shareholders which appears therein under the caption "Securities Holdings of Principal Shareholders, Directors and Officers".

Item 13. Certain Relationships and Related Transactions.

There is incorporated in this Item 13 by reference that portion of the Company's definitive proxy statement for the 1997 Annual Meeting of Shareholders which appears therein under the caption "Certain Transactions."

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a)1. Consolidated Financial Statements Page

(a)2. Financial Statement Schedules

All schedules have been omitted because they are not applicable, not required under the instructions or the information requested is set forth in the consolidated financial statements or related notes thereto.

Item 14 (b): Reports on Form 8-K Filed in the Fourth Quarter of 1996:

Form 8-K dated October 15. 1996 and amended on December 15, 1996

Item 2. Acquisition or Disposition of Assets - acquisition of Enserch Properties.

Item 7. Financial Statements and Exhibits - financial statements of Enserch Properties

Form 8-K dated November 7, 1996

Item 5. Other Events - pricing of Senior Notes placement

Form 8-K dated November 27, 1996 and amended on January 27, 1997

Item 2. Acquisition or Disposition of Assets - acquisition of Canadian Gas Gathering Systems, Inc. Acquisition of Portilla - 1996 L.P. Limited Partnership interest.

Item 5. Other Events - Senior Notes Offering, CVR maturity extension

Item 7. Financial Statements and Exhibits - Financial statements of CGGS and Portilla-1996 L.P.

(a)3. Exhibits

The following Exhibits have previously been filed by the Registrant or are included following the Index to Exhibits.

Exhibit Number. Description

3.1 Articles of Incorporation of Abraxas. (Filed as Exhibit 3.1 to the Company's Registration Statement on Form S-4, No. 33-36565 (the "S-4 Registration Statement")).

3.2 Articles of Amendment to the Articles of Incorporation of Abraxas dated October 22, 1990 (Filed as Exhibit 3.3 to the S-4 Registration Statement). 3.3 Articles of Amendment to the Articles of Incorporation of Abraxas dated December 18, 1990.
(Filed as Exhibit 3.4 to the S-4 Registration Statement).

3.4 Articles of Amendment to the Articles of Incorporation of Abraxas dated June 8, 1995. (Filed as Exhibit 3.4 to the Company's Registration Statement on Form S-3, No. 333-398 (the "S-3 Registration Statement")).

3.5 Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.5 to the S-3 Registration Statement).

3.6 Certificate of Designation of Series 1995-B Preferred Stock of Abraxas. (Filed as Exhibit 3.6 to the S-3 Registration Statement).

3.7 Articles of Incorporation of Canadian Abraxas. (Filed as Exhibit 3.7 to the Company's and Canadian Abraxas' Registration Statement on Form S-4, No. 333-18673 (the "Exchange Offer Registration Statement")).

3.8 By-Laws of Canadian Abraxas. (Filed as Exhibit 3.8 to the Exchange Offer Registration Statement).

4.1 Specimen Common Stock Certificate of Abraxas. (Filed as Exhibit 4.1 to the S-4 Registration Statement).

4.2 Specimen Preferred Stock Certificate of Abraxas. (Filed as Exhibit 4.2 to the Company's Annual Report on Form 10-K filed on March 31, 1995).

4.3 Rights Agreement dated as of December 6, 1994 between Abraxas and First Union National Bank of North Carolina ("FUNB"). (Filed as Exhibit 4.1 to the Company's Registration Statement on Form 8-A filed on December 6, 1994).

4.4 Contingent Value Rights Agreement dated November 17, 1995 by and between the Company and FUNB (Filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated November 21, 1995).

4.5 First Amendment to Contingent Value Rights Agreement dated May 2, 1996 by and between the Company and FUNB. (Filed as Exhibit 4.5 to the S-3 Registration Statement).

4.6 Indenture dated November 14, 1996 by and among the Company, Canadian Abraxas and IBJ Schroder Bank and Trust Company. (Filed as Exhibit 4.1 to the Company's Current Report on Form 8-K dated November 27, 1996).

4.7 Form of Note. (Filed as Exhibit 4.7 to the Exchange Offer Registration Statement).

4.8 Specimen Common Stock Certificate of Canadian Abraxas. (Filed as Exhibit 4.8 to the Exchange Offer Registration Statement).

*10.1 Abraxas Petroleum Corporation 1984 Non-Qualified Stock Option Plan, as amended and restated. (Filed as Exhibit 10.7 to the Company's Annual Report on Form 10-K filed April 14, 1993).

*10.2 Abraxas Petroleum Corporation 1984 Incentive Stock Option Plan, as amended and restated. (Filed as Exhibit 10.8 to the Company's Annual Report on Form 10-K filed April 14, 1993).

*10.3 Abraxas Petroleum Corporation 1993 Key Contributor Stock Option Plan. (Filed as Exhibit 10.9 to the Company's Annual Report on Form 10-K filed April 14, 1993).

*10.4 Abraxas Petroleum Corporation 401(k) Profit Sharing Plan. (Filed as Exhibit 10.4 to the Exchange Offer Registration Statement).

*10.5 Abraxas Petroleum Corporation Director Stock Option Plan. (Filed as Exhibit 10.5 to the Exchange Offer Registration Statement).

*10.6 Abraxas Petroleum Corporation Restricted Share Plan for Directors. (Filed as Exhibit 10.20 to the Company's Annual Report on Form 10-K filed on April 12, 1994).

*10.7 Abraxas Petroleum Corporation 1994 Long Term Incentive Plan. (Filed as Exhibit 10.21 to the Company's Annual Report on Form 10-K filed on April 12, 1994).

*10.8 Abraxas Petroleum Corporation Incentive Performance Bonus Plan. (Filed as Exhibit 10.24 to the Company's Annual Report on Form 10-K filed on April 12, 1994).

10.9 Registration Rights and Stock Registration Agreement dated as of August 11, 1993 by and among Abraxas, EEP and Endowment Energy Partners II, Limited Partnership ("EEP II"). (Filed as Exhibit 10.33 to the Company's Registration Statement on Form S-1, Registration No. 33-66446 (the "S- 1 Registration Statement")).

10.10 First Amendment to Registration Rights and Stock Registration Agreement dated June 30, 1994 by and among Abraxas, EEP and EEP II. (Filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on July 14, 1994).

10.11 Second Amendment to Registration Rights and Stock Registration Agreement dated September 2, 1994 by and among Abraxas, EEP and EEP II. (Filed as Exhibit 10.3 to the Company's Annual Report on Form 10-K filed March 31, 1995)

10.12 Third Amendment to Registration Rights and Stock Registration Agreement dated November 17, 1995 by and among Abraxas, EEP and EEP II. (Filed as Exhibit 10.17 to the Company's Annual Report on Form 10-K filed March 31, 1995)

10.13 Common Stock Purchase Warrant dated as of December 18, 1991 between Abraxas and EEP. (Filed as Exhibit 12.3 to the Company's Current Report on Form 8-K filed January 9, 1992).

10.14 Common Stock Purchase Warrant dated as of August 1, 1993 between Abraxas and EEP. (Filed as Exhibit 10.35 to the S-1 Registration Statement).

10.15 Common Stock Purchase Warrant dated August 11, 1993 between Abraxas and EEP II. (Filed as Exhibit 10.36 to the S-1 Registration Statement).

10.16 Common Stock Purchase Warrant dated August 11, 1993 between Abraxas and Associated Energy Managers, Inc. (Filed as Exhibit 10.37 to the S-1 Registration Statement).

10.17 Letter dated September 2, 1994 from Abraxas to EEP and EEP II. (Filed as Exhibit 10.13 to the Company's Annual Report on Form 10-K filed March 31, 1995)

10.18 Amended and Restated Credit Agreement dated as of November 14, 1996 among Abraxas, Bankers Trust Company, Inc. (U.S.) Capital Corporation and the Lenders named therein. (Filed as Exhibit 10.5 to the Company's Current Report on Form 8-K filed November 27, 1996).

10.19 Warrant Agreement dated as of July 27, 1994 between Abraxas and FUNB. (Filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed August 5, 1994).

10.20 Warrant Agreement dated as of December 16, 1994, between Abraxas and FUNB. (Filed as Exhibit 10.23 to the Company's Annual Report on Form 10-K filed March 31, 1995).

10.21 First Amendment to Warrant Agreement dated as of August 31, 1995 between Abraxas and FUNB. (Filed as Exhibit 10.21 to the S-3 Registration Statement).

10.22 Form of Indemnity Agreement between Abraxas and each of its directors and officers. (Filed as Exhibit 10.30 to the S-1 Registration Statement).

*10.23 Employment Agreement between Abraxas and Robert L. G. Watson. (Filed as Exhibit 10.23 to the S-3 Registration Statement).

*10.24 Employment Agreement between Abraxas and Chris E. Williford. (Filed as Exhibit 10.24 to the S-3 Registration Statement).

*10.25 Employment Agreement between Abraxas and Robert Patterson. (Filed as Exhibit 10.25 to the S-3 Registration Statement).

*10.26 Employment Agreement between Abraxas and Stephen T. Wendel. (Filed as Exhibit 10.26 to the S-3 Registration Statement).

10.27 Common Stock and Contingent Value Rights Purchase Agreement dated as of November 17, 1995 by and among Abraxas and the Purchasers named in Schedule l thereto. (Filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated November 21, 1995.)

10.28 Registration Agreement dated November 17, 1995 by and among the Company and the parties named in Schedule I thereto. (Filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated November 21, 1995.)

10.29 Subscription Agreement between Registrant and Grey Wolf Exploration, Ltd. (Filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated January 17, 1995.)

10.30 Subscription Agreement between Grey Wolf Exploration, Ltd. and Cascade Oil and Gas Ltd. (Filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated January 17, 1995.)

10.31 Purchase Agreement dated November 14, 1996 by and among Abraxas, Canadian Abraxas, BT Securities Corporation, Jefferies & Company, Inc. and ING Baring (U.S.) Securities Corporation (collectively, the "Initial Purchasers"). (Filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 27, 1996).

10.32 Registration Rights Agreement dated November 14, 1996 by and among Abraxas, Canadian Abraxas, and the Initial Purchasers. (Filed as Exhibit 10.2 to the Company's Current Report on Form 8- K filed November 27, 1996).

10.33 Share Sale Agreement dated October 29, 1996 by and among Abraxas, Canadian Abraxas, CGGS Canadian Gas Gathering Systems Inc. ("CGGS") and the shareholders of CGGS. (Filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed November 27, 1996).

10.34 Purchase and Sale Agreement dated September 18, 1996 by and among Abraxas, Acco, LLC, Massachusetts Bay Transportation Authority Retirement Fund, Metropolitan Life Insurance Company Separate Account No. 175, The General Mills, Inc. Master Trust: Pooled Real Estate Fund and State Street Research Energy, Inc. (Filed as Exhibit 10.4 to the Company's Current Report on Form 8-K filed November 27, 1996).

10.35 Purchase and Sale Agreement dated May 22, 1996 between Abraxas and Enserch Exploration, Inc. (Filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed October 15, 1996).

10.36 Management Agreement dated November 14, 1996 by and between Canadian Abraxas and Cascade Oil & Gas Ltd. (Filed as Exhibit 10.36 to the Exchange Offer Registration Statement).

11.1 Earnings per share Computation Statement

18.1 Letter regarding change in accounting principle. (Filed as Exhibit 18.1 to the Registrant's Annual Report on Form 10-K filed on April 12, 1994).

22.1 Subsidiaries of Abraxas. (Filed as Exhibit 22.1 to the Exchange Offer Registration Statement).

23.1 Consent of Independent Auditors. (Filed as Exhibit 23.1 to The Registrant's Annual Report on Form 10-K filed March 31, 1997).

23.2 Consent of independent, third party, Petroleum Engineers. (Filed as Exhibit 23.2 to The Registrant's Annual Report on Form 10-K filed March 31, 1997).

27.1 Financial Data Schedule.

* Management Compensatory Plan or Agreement.

INDEX TO FINANCIAL STATEMENTS

Report of Independent Auditors

The Board of Directors and Shareholders
Abraxas Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation and Subsidiaries as of December 31, 1995 and 1996, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 1996. 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 generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Abraxas Petroleum Corporation and Subsidiaries at December 31, 1995 and 1996, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1996, in conformity with generally accepted accounting principles.

ERNST & YOUNG LLP

San Antonio, Texas
March 21, 1997

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31	
	1995	1996
	(In thousands)	
Current assets:		
Cash	$ 4,250	$ 8,290
Accounts receivable, less allowance for doubtful accounts:		
Joint owners	1,335	1,601
Oil and gas production sales	2,946	11,400
Affiliates, officers, and shareholders	53	94
Other	60	1,289
	4,394	14,384
Equipment inventory	80	451
Other current assets	125	187
Total current assets	8,849	23,312
Property and equipment	104,997	310,043
Less accumulated depreciation, depletion, and amortization	29,919	38,653
Net property and equipment based on the full cost method of accounting for oil and gas properties of which $-0- and $37,268 at December 31, 1995 and 1996, respectively, were excluded from amortization	75,078	271,390
Deferred financing fees, net of accumulated amortization of $289 and $280 at December 31, 1995 and 1996, respectively	354	9,335
Restricted cash	134	90
Marketable securities	326	--
Other assets	326	715
Total assets	$ 85,067	$304,842

See accompanying notes.

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND SHAREHOLDERS' EQUITY

	December 31 1995	December 31 1996
	(In thousands)	
Current liabilities:		
Accounts payable and other accrued liabilities	$ 3,929	$ 9,960
Oil and gas production payable	1,787	2,378
Accrued interest	363	3,206
Income taxes payable	--	145
Other accrued expenses	46	1,132
Dividends payable on preferred stock	91	--
Payable to affiliates	--	58
Total current liabilities	6,216	16,879
Long-term debt:		
Senior notes	--	215,000
Financing agreements	41,557	--
Other	44	32
	41,601	215,032
Other long-term obligations	--	87
Deferred income taxes	187	32,928
Minority interest in foreign subsidiary	--	2,157
Future site restoration	--	2,103
Commitments and contingencies		
Shareholders' equity:		
Preferred stock 8%, authorized 1,000,000 shares; issued and outstanding 45,741 shares at December 31, 1995 and 1996	--	--
Common stock, par value $.01 per share - authorized 50,000,000 shares; issued 5,799,762 and 5,806,812 shares at December 31, 1995 and 1996, respectively	58	58
Additional paid-in capital	50,914	50,926
Unrealized holding loss on securities	(244)	--
Accumulated deficit	(13,664)	(12,517)
Treasury stock, at cost, 2,571, and 74,711 shares at December 31, 1995 and 1996, respective.........	(1)	(405)
Foreign currency translation adjustment	--	(2,406)
Total shareholders' equity	37,063	35,656
Total liabilities and shareholders' equity	$ 85,067	$ 304,842

See accompanying notes.

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	1994	1995	1996
	Year Ended December 31 (In thousands except shares and per share data)		
Revenue:			
Oil and gas production revenues	$ 11,114	$ 13,660	$ 25,749
Gas processing revenues	--	--	600
Rig revenues	161	108	139
Other	74	49	165
	11,349	13,817	26,653
Operating costs and expenses:			
Lease operating and production taxes	3,693	4,333	5,858
Gas processing costs	--	--	262
Depreciation, depletion, and amortization	3,790	5,434	9,605
Rig operations	133	125	169
General and administrative	810	1,042	1,933
	8,426	10,934	17,827
Operating income	2,923	2,883	8,826
Other (income) expense:			
Interest income	(16)	(34)	(254)
Amortization of deferred financing fee	400	214	280
Interest expense	2,359	3,911	6,241
Loss on marketable securities	--	--	235
Other expense	67	--	138
	2,810	4,091	6,640
Income (loss) from continuing operations before taxes and extraordinary items	113	(1,208)	2,186
Income tax expense (benefit):			
Current	--	--	176
Deferred	--	--	--
Minority interest in income of consolidated foreign subsidiary	--	--	70
Income (loss) from continuing operations before extraordinary items	113	(1,208)	1,940

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (CONTINUED)

	Year Ended December 31		
	1994	1995	1996
	(In thousands except shares and per share data)		
Discontinued operations:			
Loss from operations of discontinued coal properties	$ (348)	$ --	$ --
Loss on disposal of discontinued coal properties	(988)	--	--
Loss from discontinued operations	(1,336)	--	--
Income (loss) before extraordinary items	(1,223)	(1,208)	1,940
Extraordinary item:			
Debt extinguishment costs	(1,172)	--	(427)
Net income (loss)	(2,395)	(1,208)	1,513
Less dividend requirement on cumulative preferred stock	(183)	(366)	(366)
Net income (loss) applicable to common stock	$ (2,578)	$ (1,574)	$ 1,147
Earnings per common and common equivalent share:			
Income (loss) from continuing operations	$ (.02)	$ (.34)	$ .23
Discontinued operations	(.31)	-	-
Extraordinary items	(.27)	-	(.06)
Net income (loss) per share	$ (.60)	$ (.34)	$ .17
Weighted average shares outstanding	4,309,878	4,635,412	6,794,442

See accompanying notes.

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In thousands except share amounts)

	Preferred Stock		Common Stock		Treasury Stock	
	Shares	Amount	Shares	Amount	Shares	Amount
Balance at January 1, 1994 .	--	$ --	4,202,449	$ 42	--	$ --
Issuance of common stock for compensation	--	--	10,033	--	--	--
Issuance of preferred stock for acquisition .	45,741	4,573	--	--	--	--
Options and warrants exercised	--	--	249,408	3	--	--
Changes in unrealized holding loss on securities	--	--	--	--	--	--
Dividend on preferred stock	--	--	--	--	--	--
Net loss for the year ...	--	--	--	--	--	--
Balance at December 31, 1994	45,741	4,573	4,461,890	45	--	--
Issuance of common stock for compensation	--	--	7,872	--	--	--
Issuance of common stock	--	--	1,330,000	13	--	--
Treasury stock purchased, net	--	--	--	--	2,571	(1)
Changes in preferred stock par value	--	(4,573)	--	--	--	--
Dividend on preferred stock	--	--	--	--	--	--
Net loss for the year ...	--	--	--	--	--	--
Balance at December 31, 1995	45,741	--	5,799,762	58	2,571	(1)
Issuance of common stock for compensation	--	--	5,050	--	(2,500)	1
Expenses paid related to private placement offering..............	--	--	--	--	--	--
Options exercised	--	--	2,000	--	--	--
Treasury stock purchased	--	--	--	--	74,640	(405)
Dividend on preferred stock	--	--	--	--	--	--
Foreign currency translation adjustment	--	--	--	--	--	--
Changes in unrealized holding loss on securities	--	--	--	--	--	--
Net income for the year .	--	--	--	--	--	--
Balance at December 31, 1996	45,741	$ --	5,806,812	$ 58	74,711	$ (405)

See accompanying notes.

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In thousands except share amounts)

	Additional Paid-In Capital	Unrealized Holding Loss on Securities	Accumulated Deficit	Foreign Currency Translation	Total
Balance at January 1, 1994 .	$ 34,614	$ --	$ (9,513)	$ --	$ 25,143
Issuance of common stock for compensation	107	--	--	--	107
Issuance of preferred stock for acquisition .	--	--	--	--	4,573
Options and warrants .... exercised	1,496	--	--	--	1,499
Changes in unrealized holding loss on .... securities	--	(244)	--	--	(244)
Dividend on preferred ... stock	--	--	(183)	--	(183)
Net loss for the year ...	--	--	(2,394)	--	(2,394)
Balance at December 31, 1994	36,217	(244)	(12,090)	--	28,501
Issuance of common stock for compensation	74	--	--	--	74
Issuance of common stock	10,050	--	--	--	10,063
Treasury stock purchased, net	--	--	--	--	(1)
Changes in preferred stock par value	4,573	--	--	--	--
Dividend on preferred ... stock	--	--	(366)	--	(366)
Net loss for the year ...	--	--	(1,208)	--	(1,208)
Balance at December 31, 1995	50,914	(244)	(13,664)	--	37,063
Issuance of common stock for compensation	41	--	--	--	42
Expenses paid related to private placement ..... offering	(42)	--	--	--	(42)
Options exercised	13	--	--	--	13
Treasury stock purchased	--	--	--	--	(405)
Dividend on preferred stock	--	--	(366)	--	(366)
Foreign currency translation adjustment	--	--	--	(2,406)	(2,406)
Changes in unrealized holding loss on securities	--	244	--	--	244
Net income for the year .	--	--	1,513	--	1,513
Balance at December 31, 1996	$ 50,926	$ --	$ (12,517)	$ (2,406)	$ 35,656

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	1994	1995	1996
	(In thousands)		
Operating Activities			
Net income (loss)	$ (2,395)	$ (1,208)	$ 1,513
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Minority interest in income of foreign subsidiary	--	--	70
Loss on disposal of discontinued operations	987	--	--
Depreciation, depletion, and amortization	3,790	5,434	9,605
Amortization of deferred financing fees	467	214	280
Issuance of common stock for compensation	107	74	42
Loss on marketable securities	--	--	235
Net loss from debt restructurings	1,172	--	427
Changes in operating assets and liabilities:			
Accounts receivable	(814)	(807)	(6,013)
Equipment inventory	(9)	(29)	(82)
Other assets	(74)	2	(133)
Accounts payable, accrued expenses, and dividends payable	1,232	(79)	7,009
Oil and gas production payable	(62)	919	591
Net cash provided by operating activities	4,401	4,520	13,544
Investing Activities			
Capital expenditures, including purchases and development of properties	(36,444)	(12,330)	(87,793)
Payment for purchase of CGGS, net of cash acquired	--	--	(85,362)
Proceeds from sale of oil and gas properties and equipment inventory	70	2,556	242
Purchase of interest in real estate partnership	--	(311)	--
Proceeds from sale of marketable securities	--	--	335
Sale of common stock in Castle Minerals	371	--	--
Net cash used in investing activities	(36,003)	(10,085)	(172,578)

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (CONTINUED)

	Year Ended December 31		
	1994	1995	1996
	(In thousands)		
Financing Activities			
Preferred stock dividends	$ (91)	$ (366)	$ (366)
Issuance of common stock, net of expenses	1,499	10,063	(29)
Purchase of treasury stock, net	--	(1)	(405)
Proceeds from long-term borrowings	40,906	5,950	305,400
Payments on long-term borrowings	(12,659)	(5,646)	(131,969)
Deferred financing fees	(451)	(186)	(9,688)
Other	--	--	87
Net cash provided by financing activities	29,204	9,814	163,030
Increase (decrease) in cash	(2,398)	4,249	3,996
Cash at beginning of year	2,533	135	4,384
Cash at end of year, including restricted cash	$ 135	$ 4,384	$ 8,380
Supplemental Disclosures			
Supplemental disclosures of cash flow information:			
Interest paid	$ 2,150	$ 3,884	$ 3,863

Supplemental schedule of noncash investing and financing activities:

During 1996, the Company purchased all of the capital stock of CGGS Canadian Gas Gathering Systems, Inc. for $85,362,000, net of cash acquired. In conjunction with the acquisition, liabilities assumed were as follows (in thousands):

Fair value of assets acquired	$ 123,970
Cash paid for the capital stock	(85,362)
Liabilities assumed	$ 38,608

During 1994, the Company issued $4,574,000 of preferred stock in exchange for oil and gas producing properties.

See accompanying notes.

1. Organization and Significant Accounting Policies

Nature of Operations

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

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Marketable Securities

Management determines the appropriate classification of marketable equity and debt securities at the time of purchase and reevaluates such designation as of each balance sheet date. Debt securities that the Company has both the positive intent and ability to hold to maturity are carried at amortized cost. Debt securities that the Company does not have the positive intent and ability to hold to maturity and all marketable equity securities are classified as available-for-sale or trading and carried at fair value. Unrealized holding gains and losses on securities classified as available-for-sale are carried as a separate component of shareholders' equity. Unrealized holding gains and losses on securities classified as trading are reported in earnings.

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables, interest rate 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. For further information regarding the Company's swap arrangements, see Notes 6 and 16.

Equipment Inventory

Equipment inventory consists of casing, tubing, and compressing equipment and is carried at the lower of cost or market.

Oil and Gas Properties

The Company follows the full cost method of accounting for crude oil and natural gas properties. Under this method, all costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. The Company does not capitalize internal costs. Depreciation, depletion, and amortization (DD&A) of capitalized crude oil and natural gas properties and estimated future development costs are based on the unit-of-production method. Net capitalized costs of crude oil and natural gas properties are limited to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves 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. No gain or loss is recognized upon sale or disposition of crude oil and natural gas properties, except in unusual circumstances.

Unevaluated properties not currently being amortized included in oil and gas properties were $-0- and $37,268,000 at December 31, 1995 and 1996, respectively. The properties represented by these costs were undergoing exploration activities or are properties on which the Company intends to commence activities in the future. The Company believes that the unevaluated properties at December 31, 1996 will be substantially evaluated in six to thirty-six months and it will begin to amortize these costs at such time.

Other Property and Equipment

Other property and equipment are recorded on the basis of cost. Depreciation of gas gathering and processing facilities and 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.

Stock-Based Compensation

Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation," encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. The Company has chosen to continue to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," 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 (see Note 8).

Foreign Currency Translation

The functional currency for the Company's Canadian operations is the Canadian dollar. The Company translates the functional currency into U.S. dollars 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 Cumulative Foreign Exchange Translation Adjustment in Shareholders' Equity.

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 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 estimated costs of restoration and removal of major processing facilities are accrued on a straight-line basis over the life of the property. The estimated future costs for known environmental remediation requirements are accrued when it is probable that a liability has been incurred and the amount of remediation costs can be reasonably estimated. These amounts are the undiscounted, future estimated costs under existing regulatory requirements and using existing technology.

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. Revenue from the processing and gathering of natural gas is recognized in the period the service is performed.

Deferred Financing Fees

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

Federal Income Taxes

The Company records income taxes under Financial Accounting Standards Board Statement No. 109 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.

Net Income (Loss) Per Common Share

Net income (loss) per common share is computed by dividing net income (loss) (adjusted for dividends on preferred stock) by the weighted average number of shares of common and common equivalent shares outstanding during the period. The weighted average number of common and common equivalent shares includes the number of shares that would be issuable under the Contingent Value Rights Agreement (CVR Agreement), if the current market value of the Company's common stock at year-end is less than a specified target price (see Note 7). Common stock equivalents, including any shares issuable under the CVR Agreement, are not considered in the computation of periods with a loss, as their effect is anti-dilutive.

Reclassifications

Certain balances for 1994 and 1995 have been reclassified for comparative purposes.

2. Acquisitions and Divestitures

Wyoming Properties Acquisition

On September 30, 1996, the Company acquired interests in certain producing crude oil and natural gas properties located in the Wamsutter area of southwestern Wyoming (the Wyoming Properties) from Enserch Exploration, Inc. The initially agreed to purchase price of $47,500,000 was adjusted to $45,122,000 to reflect adjustments of net production revenue which accrued to the Company from April 1, 1996, the effective date, until closing, net of interest owed by the Company for the same period and transaction costs. The acquisition was accounted for as a purchase and the purchase price was allocated to crude oil and natural gas properties based on the fair values of the properties acquired. The transaction was financed through borrowings under the Company's bridge facility referred to in Note 6. Revenues and expenses from the Wyoming Properties have been included in the consolidated financial statements since September 30, 1996.

CGGS Acquisition

On November 14, 1996, the Company, through its wholly owned subsidiary, Canadian Abraxas Petroleum Limited (Canadian Abraxas), purchased 100% of the outstanding capital stock of CGGS Canadian Gas Gathering Systems Inc. (CGGS) for approximately $85,500,000, net of the CGGS cash acquired and including transaction costs. CGGS owns producing oil and gas properties in western Canada and adjacent gas gathering and processing facilities as well as undeveloped leasehold properties. Immediately after the purchase, CGGS was merged with and into Canadian Abraxas. The acquisition was accounted for as a purchase and the purchase price was allocated to the assets and liabilities based on estimated fair values. The transaction was financed by a portion of the proceeds from the offering of $215,000,000 of Notes referred to in Note 6. Revenues and expenses from Canadian Abraxas have been included in the consolidated financial statements since November 14, 1996.

Grey Wolf Acquisition

In January 1996, the Company made a $3,000,000 investment in Grey Wolf Exploration Ltd. (Grey Wolf), a privately held Canadian corporation, which in turn invested in newly issued shares of Cascade Oil and Gas Ltd. (Cascade), an Alberta, Canada corporation whose shares are traded on the Alberta Stock Exchange. The Company owns 78% of the outstanding capital stock of Grey Wolf, and, through Grey Wolf, the Company owns approximately 52% of the outstanding capital stock of Cascade. The acquisition was accounted for as a purchase and the purchase price was allocated to the assets and liabilities based on the fair values. Revenues and expenses have been included in the consolidated financial statements since January 1996. Certain officers and directors of the Company own approximately 6% of the common stock of Grey Wolf and serve as directors of Grey Wolf.

Portilla and Happy Fields Acquisition

In March 1996, the Company sold all of its interest in its Portilla and Happy Fields to an unrelated purchaser (Purchaser or Limited Partner). Simultaneously with this sale, the Limited Partner also acquired the 50% overriding royalty interest in the Portilla Field owned by the Commingled Pension Trust Fund Petroleum II, the trustee of which is Morgan Guaranty Trust Company of New York (Pension Fund). In connection with the purchase of both the Company's interest in the Portilla and Happy Fields and the Pension Fund's interest in the Portilla Field (together, the Portilla and Happy Properties), the Limited Partner obtained a loan (Bank Loan) secured by the Properties and contributed the Properties to Portilla-1996, L.P., a Texas limited partnership (Partnership). A subsidiary of the Company, Portilla-Happy Corporation (Portilla-Happy), was the general partner of the Partnership. The aggregate purchase price received by the Company was $17,600,000, of which $2,000,000 was used to purchase a minority interest in the Partnership.

On November 14, 1996, the Company closed an agreement with the Limited Partner and certain noteholders (Noteholders) of the Partnership, pursuant to which the Company obtained the Limited Partner's interest in the Partnership and the Noteholders' notes in the aggregate principal amount of $5,920,000 (Notes), resulting in the Company's owning, on a consolidated basis, all of the equity interests in the Partnership. The aggregate consideration paid to the Limited Partner and the Noteholders was $6,961,000. The Company also paid off the Bank Loan which had an outstanding principal balance of approximately $20,051,000, and assumed a crude oil and natural gas price swap agreement (see Note 16).

As a result of obtaining the Limited Partner's interest in the Partnership, the Company reacquired those interests in the Portilla and Happy Fields which it previously owned, as well as the interest in the Portilla Field previously owned by the Pension Fund. The Company has included in its balance sheet the amount previously removed from oil and gas properties in connection with the sale of its interest in the Portilla and Happy Fields during the quarter ended March 31, 1996, as well as the amount of the purchase price paid for the Pension Fund's interest in the Portilla Field, and all development drilling expenditures incurred on the properties, less the amount of DD&A related to the properties from the formation of the Partnership through the closing of the transaction. The purchase was financed by a portion of the proceeds from the offering of the Notes referred to in Note 6. The Company recorded its share of the net loss of the Partnership from March 1996 to November 1996 of $513,000. The Company also assumed and wrote off the remaining deferred financing fees and organization costs of the Partnership. Gross revenues and expenses from both the Company's original interest in the Portilla and Happy Fields as well as the interest in the Portilla Field previously owned by the Pension Fund have been included in the consolidated financial statements since November 14, 1996.

East White Point and Stedman Island Fields Acquisition

In November 1996, the Company obtained a release of the 50% overriding royalty interest in the East White Point Field in San Patricia County, Texas and the Stedman Island Field in Nueces County, Texas from the Pension Fund for $9,271,000 before adjustment for accrual of net revenue to closing. The acquisition was accounted for as a purchase and the purchase price was allocated to crude oil and natural gas properties based on the fair values of the properties acquired. The transaction was financed through proceeds of the sale of the Notes referred to in Note 6. Revenues and expenses from these properties have been included in the consolidated financial statements since November 1, 1996. The Company recorded the net purchase price of approximately $9,271,000 to its oil and gas properties.

Miscellaneous Working Interests

During 1996, the Company also acquired additional working interests in certain producing crude oil and natural gas properties in which the Company had existing working interest ownership. The net purchase price amounted to approximately $1,221,000. Revenue and expenses have been included in the consolidated financial statement from the date of purchase.

Texas Gulf Coast Properties Acquisition

In October 1995, the Company acquired additional working interests in certain producing crude oil and natural gas properties in which the Company had an existing working interest ownership. The net purchase price to Abraxas amounted to approximately $635,000. Revenues and expenses have been included in the consolidated financial statements since October 1, 1995.

West Texas Properties Acquisition

In July 1994, the Company acquired from various parties interests in certain producing crude oil and natural gas properties located in West Texas (the West Texas Properties). The net purchase price to Abraxas amounted to approximately $28,242,000 including closing costs of approximately $383,000. The acquisition was accounted for as a purchase and the purchase price was allocated to crude oil and natural gas properties based on the fair values of the properties acquired. The transaction was financed principally by additional borrowings under the Company's credit agreement with First Union National Bank of North Carolina (First Union), referred to in Note 6. Revenue and expenses from the West Texas Properties have been included in the consolidated financial statements since July 1, 1994.

Overriding Royalty Interest Acquisition

In June 1994, the Company acquired from its prior secured lenders, Endowment Energy Partners, L.P. (EEP) and Endowment Energy Co-Investment Partnership (EECIP), 80% of the previously granted overriding royalty interests. The net purchase price of approximately $5,174,000 consisted of $600,000 cash and 45,741 shares of the Company's Series B 8% nonvoting cumulative convertible preferred stock with a par value of $100 per share (Series B Preferred) at the time of issuance. The preferred shares were recorded at $4,574,100 at the date of the acquisition. In November 1995, the Company exchanged the Series B Preferred for an equal number of shares of its Series 1995-B Preferred Stock, par value $.01 per share, with a stated value of $100 per share. The preferred shares are convertible into 508,182 shares of the Company's common stock. The acquisition was accounted for as a purchase, and the purchase price was allocated to crude oil and natural gas properties based on the fair values of the properties acquired. The cash portion of the transaction was financed principally under the Company's credit agreement with First Union. Revenues and expenses related to these properties have been included in the consolidated financial statements since July 1, 1994.

The condensed pro forma financial information for the periods presented below summarize on an unaudited pro forma basis approximate results of the Company's consolidated operations for the years ended December 31, 1994, 1995 and 1996 assuming the acquisitions of the Wyoming Properties, CGGS, Grey Wolf, the Portilla and Happy Properties, and the East White Point and Stedman Island Fields occurred at January 1, 1995; and the acquisition of the West Texas Properties and Overriding Royalty Interest occurred at January 1, 1994. The pro forma information does not necessarily represent what the actual consolidated results would have been for these periods and is not intended to be indicative of future results.

	December 31		
	1994	1995	1996
	(In thousands except per share data) (Unaudited)		
Revenues	$ 13,972	$ 46,132	$ 60,077
Income (loss) before discontinued operations and extraordinary items	$ (186)	$(16,430)	$ (6,665)
Net income (loss)	$ (2,693)	$(16,430)	$ (7,092)
Income (loss) per common share:			
Before discontinued operations and extraordinary items	$ (.13)	$ (3.54)	$ (.98)
Net income (loss)	$ (.71)	$ (3.54)	$ (1.04)

Divestiture

In July 1995, the Company sold its C.S. Dean Unit for approximately $2,550,000.

3. Marketable Securities

In May 1993, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS 115), effective for fiscal years beginning after December 15, 1993. At December 31, 1994, the Company's marketable equity securities were classified as available-for-sale. As of December 31, 1994, the Company recognized a decrease of approximately $244,000 in shareholders' equity, representing the recognition in shareholders' equity of unrealized depreciation, net of taxes, for the Company's investment in equity securities determined to be available-for-sale, previously carried at the lower of cost or market.

The securities had an original cost of $570,000. In October 1996, the Company sold its investment in marketable securities, realizing a loss of $235,000, which was recognized in the statement of operations for the year ended December 31, 1996.

4. Property and Equipment

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

	Estimated Useful Life	1995	1996
	Years	(In thousands)	
Land, buildings, and improvements ..	15	$ 177	$ 269
Crude oil and natural gas properties	--	104,127	268,358
Natural gas processing plants	18	--	40,100
Equipment and other	7	693	1,316
		$104,997	$310,043

5. Related Party Transactions

Accounts receivable from affiliates, officers, and shareholders represent amounts receivable relating to joint interest billings on properties which the Company operates and advances made to officers.

In connection with a note payable to the Company's President, principal and interest payments amounted to $333,000 and $355,000 in the years ended December 31, 1994 and 1995, respectively. The note was fully paid in 1995.

Wind River Resources Corporation ("Wind River"), all of the capital stock of which is owned by the Company's President, owns a twin-engine airplane. The airplane is available for business use by employees of the Company from time to time at $385 per hour. The Company paid Wind River a total of $81,000 and $101,000 for use of the plane during 1995 and 1996, respectively.

The Company's President and certain directors of the Company were founders of Grey Wolf and in April 1995 purchased 900,000 shares of the capital stock of Grey Wolf (initially representing 39% of the outstanding shares) for an aggregate of CDN$90,000 (or CDN$0.10 per share) in cash. In January 1996, the Company purchased 20,325,096 shares of the capital stock of Grey Wolf (representing 78% of the outstanding shares) for an aggregate of $3,000,000 (approximately CDN$4.1 million or CDN$.20 per share) in cash. The Company's President and certain directors, as well as the two principal officers of Grey Wolf, currently own 13.8% of the issued and outstanding capital stock of Grey Wolf. In addition, the Company's President owns options to purchase up to 450,000 shares of Grey Wolf's capital stock at an exercise price of CDN$.10 per share.

In January 1996, Grey Wolf purchased newly issued shares of Cascade representing 66 2/3% of Cascade's capital stock. Certain of the Company's directors as well as the two principal officers of Grey Wolf own options to purchase in the aggregate up to 2,600,000 shares of capital stock of Cascade at a exercise price of CDN$.20 per share, and the Company's President owns options to purchase up to 800,000 shares of Cascade's capital stock at an exercise price of CDN$.34 per share.
Cascade currently has 61,365,000 shares of capital stock outstanding.

6. Long-Term Debt

Long-term debt consists of the following:

	December 31 1995	December 31 1996
	(In thousands)	
11.5% Senior Notes due 2004 (see below)	$ --	$215,000
Credit facility due to Bankers Trust Company, ING Capital and Union Bank of California (see below)	--	--
Revolving lines of credit due under the First Union credit agreement (see below)	35,557	--
Term notes due under the First Union credit agreement (see below)	6,000	--
Other	44	32
	41,601	215,032
Less current maturities	--	--
	$ 41,601	$215,032

On November 14, 1996, the Company and Canadian Abraxas completed the sale of $215,000,000 aggregate principal amount of Senior Notes due November 1, 2004 (Notes). Interest at 11.5% is payable semi-annually in arrears on May 1 and November 1 of each year, commencing on May 1, 1997. The Notes are general unsecured obligations of the Company and Canadian Abraxas and rank pari passu in right of payment to all future subordinated indebtedness of the Company and Canadian Abraxas. The Notes are, however, effectively subordinated in right of payment to all existing and future secured indebtedness to the extent of the value of the assets securing such indebtedness. The Company and Canadian Abraxas are joint and several obligors on the Notes. The Notes are redeemable, in whole or in part, at the option of the Company and Canadian Abraxas on or after November 1, 2000, at the redemption price of 105.75% through October 31, 2001, 102.87% through October 31, 2002 and 100.00% thereafter plus accrued interest. In addition, any time on or prior to November 1, 1999, the Company and Canadian Abraxas may redeem up to 35% of the aggregate principal amount of the Notes originally issued with the cash proceeds of one or more equity offerings at a redemption price of 111.5% of the aggregate principal amount of the Notes to be redeemed plus accrued interest, provided, however, that after giving effect to such redemption, at least $139,750,000 aggregate principal amount of Notes remains outstanding. The Notes were issued under the terms of an Indenture dated November 14, 1996 that contains, among others, certain covenants which generally limit the ability of the Company to incur additional indebtedness other than specific indebtedness permitted under the Indenture, including the Credit Facility discussed below, provided however, if no event of default is continuing, the Company may incur indebtedness if after giving pro forma effect to the incurrence of such debt both the Company's consolidated earnings before interest, taxes, depletion and amortization (EBITDA) coverage ratio would be greater than 2.25 to 1.0 if prior to November 1, 1997, and at least equal to 2.5 to 1.0 thereafter and the Company's adjusted consolidated net tangible assets as defined are greater than 150% of the aggregate consolidated indebtedness of the Company. The Indenture also contains other covenants affecting the Company's ability to pay dividends on its common stock, sell assets and incur liens.

On September 30, 1996, the Company entered into a credit facility with Bankers Trust Company (BTCo) and ING Capital (together the Lenders), providing a bridge facility in the total amount of $90,000,000 and borrowed $85,000,000 which was used to repay all amounts due under the First Union credit agreement and to finance the purchase of the Wyoming Properties.

On November 14, 1996, the Company repaid all amounts outstanding under the bridge facility with proceeds from the offering of $215,000,000 of Notes described above and entered into an amended and restated credit agreement (Credit Facility) with the Lenders and Union Bank of California. The Credit Facility provides for a revolving line of credit with an initial availability of $20,000,000, subject to a borrowing base condition. No amounts were outstanding on December 31, 1996.

Commitments available under the Credit Facility are subject to borrowing base redeterminations to be performed semi-annually and, at the option of each of the Company and the Lenders, one additional time per year. Amounts due under the Credit Facility will be secured by the Company's oil and gas properties and plants. Any outstanding principal balance in excess of the borrowing base will be due and payable in three equal monthly payments after a borrowing base redetermination. The borrowing base will be determined in the agent's sole discretion, subject to the approval of the Lenders, based on the value of the Company's reserves as set forth in the reserve report of the Company's independent petroleum engineers, with consideration given to other assets and liabilities.

The Credit Facility has an initial revolving term of two years and a reducing period of three years from the end of the initial two-year period. The commitment under the Credit Facility will be reduced during such reducing period by eleven equal quarterly reductions. Quarterly reductions will equal 8.2% per quarter with the remainder due at the end of the three-year reducing period.

The applicable interest rate charged on the outstanding balance of the Credit Facility is based on a facility usage grid. If the borrowings under the Credit Facility represent an amount less than or equal to 33.3% of the available borrowing base, then the applicable interest rate charged on the outstanding balance will be either (a) an adjusted rate of the London Inter-Bank Offered Rate ("LIBOR") plus 1.25% or (b) the prime rate of the agent (which is based on the agent's published prime rate) plus 0.50%. If the borrowings under the Credit Facility represent an amount greater than or equal to 33.3% but less than 66.7% of the available borrowing base, then the applicable interest rate on the outstanding principal will be either (a) LIBOR plus 1.75% or (b) the prime rate of the agent plus 0.50%. If the borrowings under the Credit Facility represent an amount greater than or equal to 66.7% of the available borrowing base, then the applicable interest rate on the outstanding principal will be either (a) LIBOR plus 2.00% or (b) the prime rate of the agent plus 0.50%. LIBOR elections can be made for periods of one, three or six months.

The Credit Facility contains a number of covenants that, among other things, restrict the ability of the Company to (i) incur certain indebtedness or guarantee obligations, (ii) prepay other indebtedness including the Notes, (iii) make investments, loans or advances, (iv) create certain liens, (v) make certain payments, dividends and distributions, (vi) merge with or sell assets to another person or liquidate, (vii) sell or discount receivables, (viii) engage in certain intercompany transactions and transactions with affiliates, (ix) change its business, (x) experience a change of control and (xi) make amendments to its charter, by-laws and other debt instruments. In addition, under the Credit Facility the Company is required to comply with specified financial ratios and tests, including minimum debt service coverage ratios, maximum funded debt to EBITDA tests, minimum net worth tests and minimum working capital tests. The Company is obligated to pay the Lenders on a quarterly basis a commitment fee of 0.50% per annum on the average unused portion of the commitment in effect from time to time. The Credit Facility contains customary events of default, including nonpayment of principal, interest or fees, violation 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 and change of control.

As part of the bridge facility, the Company entered into an interest rate swap agreement (the Swap) covering the period from September 18, 1996 to August 18, 1998. The Swap effectively changes the interest rate on $25,000,000 of floating rate debt to a fixed rate of 6.15% per annum for that time period. Net payments due under this agreement are included as adjustments to interest expense. At December 31, 1996, the fair value of this Swap, as determined by BTCo was approximately $200,000 and has been recorded as interest expense at December 31, 1996. The Company is exposed to credit loss in the event of nonperformance by the counterparty. The amount of such exposure is generally the unrealized gains in such agreement.

In June 1994, the Company entered into a credit agreement with First Union and secured advances adequate to extinguish the total debt and accrued interest owed to the Company's previous lenders. The prepayment resulted in the Company recording an extraordinary debt extinguishment charge of $1,172,000, representing the reduction of the deferred financing fees related to the prior debt. At December 31, 1995, the Company's borrowings under the credit agreement were $41,557,000. The borrowings were composed of advances of $12,657,000 and $22,900,000 under the revolving lines of credit which were due June 30, 1997, and $6,000,000 under the term notes which were also due June 30, 1997. The interest rate for the revolving credit lines was, at the option of the Company, either (a) the higher of First Union prime plus 1/4% or the federal funds rate plus 3/4%, floating, payable monthly, or (b) LIBOR plus 2 1/4% (30-, 60-, 90-, and 180-day options), with interest payable the earlier of maturity of each LIBOR tranche or quarterly. The interest rate for the term notes were, at the option of the Company, either (a) the higher of First Union prime plus 3/4% or the federal funds rate plus 1 1/4%, floating, payable monthly, or (b) LIBOR plus 3 1/4% (30-, 60-, 90-, and 180-day options), with interest payable the earlier of maturity of each LIBOR tranche or quarterly. At December 31, 1995, the $12,657,000 revolver carried interest at 8.19%, the $22,900,000 revolver carried interest at 8.06%, and the term notes at 8.16%. The revolvers provided for borrowing based principally on the Company's crude oil and natural gas reserve base, which was $44,000,000 at December 31, 1995 and such borrowings were secured by a first-priority mortgage on all of the Company's crude oil and natural gas properties and gas plants, as well as a security interest in accounts receivable, inventory, contracts, and general intangibles, and are guaranteed by the Company. As discussed above, in September 1996, the Company entered into a new credit facility and extinguished the total debt and accrued interest owed to First Union. The prepayment resulted in the Company recording an extraordinary debt extinguishment charge of $427,000 representing the reduction of the deferred financing fees related to the debt.

The Company's principal source of funds to meet debt service and capital requirements is net cash flow provided by operating activities, which is sensitive to the prices the Company receives for its crude oil and natural gas. The Company has recently entered into hedge agreements to reduce its exposure to price risk in the spot market for natural gas. However, a substantial portion of the Company's production will remain subject to such price risk. Additionally, significant capital expenditures are required for drilling and development, and other equipment additions. The Company believes that cash provided by operating activities and other financing sources, including, if necessary, the sale of certain assets and additional long-term debt, will provide adequate liquidity for the Company's operations, including its capital expenditure program, for the next twelve months. No assurance, however, can be given that the Company's cash flow from operating activities will be sufficient to meet planned capital expenditures and debt service in the future. Should the Company be unable to generate sufficient cash flow from operating activities to meet its obligations and make planned capital expenditures, the Company could be forced to reduce such expenditures or sell assets in order to meet its obligations.

During 1996, the Company capitalized $465,000 of interest expense.

The fair value of the Notes approximates their carrying value as of December 31, 1996. The Company has approximately $60,000 of standby letters of credit and a $30,000 performance bond open at December 31, 1996. Approximately $90,000 of cash is restricted and in escrow related to the letters of credit and bond.

7. Shareholders' Equity

Common Stock

Holders of common stock are entitled to one vote for each share and are not entitled to preemptive rights to subscribe to additional shares of common stock issued by the Company. Holders are entitled to receive dividends as may be declared by the Board of Directors, subject to the rights of holders of preferred stock and the terms of the Company's credit agreement, which restrict the payment of dividends.

In 1994, the Board of Directors adopted a Shareholders' 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 $20 one-half of one share of common stock of the Company having a value of four 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.

In November 1995, the Company issued 1,330,000 units, each consisting of one share of common stock and one Contingent Value Right (CVR), through a private placement, resulting in net proceeds of $10,063,000. Each CVR allows the holder the right to acquire additional shares of common stock under certain circumstances. See further discussion of CVRs below. Loss per share, calculated on a supplemental basis as if the foregoing event had occurred at the beginning of 1995, would have been $(.19) for the year ended December 31, 1995. The supplemental earnings per share assumes that interest expense would have been reduced by $456,000 from the prepayment of $5,300,000 of long-term debt from the proceeds of the issuance of the units for the year ended December 31, 1995.

Preferred Stock

In June 1994, in connection with the Company's acquisition of the overriding royalty interest from EEP and EECIP, 45,741 shares of the Company's Series B 8%, nonvoting cumulative convertible preferred stock with a par value of $100 were issued. The preferred shares are convertible into 508,182 shares of the Company's common stock. Preferred stock dividends during 1995 and 1996 amounted to $366,000. During 1995, the Company exchanged the Series B 8%, nonvoting cumulative convertible preferred stock for an equal number of shares of Series 1995-B cumulative convertible preferred stock which have a par value of $.01 per share and a stated value of $100 per share. The Board of Directors of the Company is authorized to approve the issuance of one or more classes or series of preferred stock without further authorization of the Company's shareholders.

Contingent Value Rights (CVR)

The CVRs were issued under the CVR Agreement between the Company, the purchasers, and First Union, as rights agents. The CVR Agreement provides that, subject to adjustment as described below, the Company shall issue for each CVR on the Extended Maturity Date (November 17, 1997), a number of shares of common stock, if any, equal to (a) the Target Price ($12.50 on the Extended Maturity Date) minus the current market value divided by (b) the current market value, provided, however, that in no event shall more than 1.5 shares of common stock be issued in exchange for each CVR at the Extended Maturity Date. Such determination by the Company shall be final and binding on the Company and the holders of CVRs.

If the median of the average prices of the common stock for the three 20-trading day periods immediately preceding the Extended Maturity Date, equals or exceeds $12.50 on the Extended Maturity Date, no shares of the common stock will be issuable with respect to the CVRs. In addition, the CVRs will terminate if the per share market value equals or exceeds the Target Price for any period of 30 consecutive trading days during the period from and after November 17, 1996 to and including November 17, 1997.

In the event that the Company determines that no shares of the common stock are issuable with respect to the CVRs to such holders, the CVRs shall terminate and become null and void and the holders shall have no further rights with respect thereto. If the Maturity Date of the CVR Agreement had been December 31, 1996, an aggregate of 1,013,060 shares of common stock would have been issued to the holders of the CVRs.

Should any additional shares of common stock be required to be issued under the terms of the CVR Agreement, such issuance will be considered to be an adjustment to the original sales price per share received in connection with the sale of the associated common shares; accordingly, the Company will increase its common stock account for the par value related to the additional shares at the time such shares are issued with a corresponding decrease in additional paid-in capital account.

Treasury Stock

During the year ended December 31, 1996, the Company purchased 74,640 shares of its common stock at a cost of $405,000, which are being held as treasury stock.

8. Stock Option Plans and Warrants

Stock Options

The Company grants options to its officers, directors, and key employees under its 1984 Incentive Stock Option Plan, Non-Qualified Stock Option Plan, Key Contributor Stock Option Plan, Long-Term Incentive Plan, and Director Stock Option Plan.

The Company has elected to follow Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25) and related Interpretations in accounting for its employee stock options because, as discussed below, the alternative fair value accounting provided for under FASB Statement No. 123, "Accounting for Stock-Based Compensation," requires use of option valuation models that were not developed for use in valuing employee stock options. Under APB 25, because the exercise price of the Company's employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized.

The Company's various stock option plans have authorized the grant of options to management and directors personnel for up to approximately 795,000 shares of the Company's common stock. All options granted have ten year terms and vest and become fully exercisable over four years of continued service at 25% on each anniversary date.

Pro forma information regarding net income and earnings per share is required by Statement 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, 1994 under the fair value method of that Statement. 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 1995 and 1996, respectively: risk-free interest rates of 6.25% and 6.25%; dividend yields of -0-% and -0-%; volatility factors of the expected market price of the Company's common stock of .383 and .383; and a weighted-average expected life of the option of six 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 (in thousands except for earnings per share information):

	1995	1996
	(In thousands)	
Pro forma net income (loss)	$ (1,652)	$ 884
Pro forma earnings per share:		
Primary	$ (.36)	$ .13

Because Statement 123 is applicable only to options granted subsequent to December 31, 1994, its pro forma effect will not be fully reflected until 1997.

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

	1994		1995		1996	
	Options (000s)	Weighted-Average Exercise Price	Options (000s)	Weighted-Average Exercise Price	Options (000s)	Weighted-Average Exercise Price(1)
Outstanding-beginning of year	133	$ 6.62	103	$ 7.93	219	$ 6.71 (1)
Granted	27	10.45	158	9.50	358	6.58
Exercised	(38)	4.64	-	-	(2)	6.75
Forfeited	(19)	8.91	(42)	9.86	(24)	9.21
Outstanding-end of year ...	103	$ 7.93	219	$ 8.69	551	$ 6.63
Exercisable at end of year	28	$ 7.43	53	$ 8.06	93	$ 6.65
Weighted-average fair value of options granted during the year				$ 2.85		$ 3.46

Exercise prices for options outstanding as of December 31, 1996 ranged from $5.00 to $7.50. The weighted-average remaining contractual life of those options is 8.6 years.

(1) In March 1996, the Company amended the exercise price to $6.75 per share on all previously issued options with an exercise price greater than $6.75 per share.

Stock Awards

In addition to stock options granted under the plans described above, the Long-Term Incentive Plan also provides for the right to receive compensation in cash, awards of common stock, or a combination thereof. In 1995 and 1996, the Company made direct awards of common stock of 4,800 shares and 1,000 shares, respectively.

The Company also has adopted the Restricted Share Plan for Directors which provides for awards of common stock to nonemployee 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. In 1995 and 1996, the Company made direct awards of common stock of 3,072 shares and 4,050 shares, respectively.

During 1996, the Company's shareholders approved the Abraxas Petroleum Corporation Director Stock Option Plan (Plan), which authorizes the grant of nonstatutory options to acquire an aggregate of 104,000 common shares to those persons who are directors and not officers of the Company. Under the Plan, each of the seven eligible directors was granted an option to purchase 8,000 common shares at $6.75. These options are included in the above table.

Stock Warrants

In connection with the EEP and EECIP financing agreements entered into in 1992 and 1993, the Company granted stock warrants covering 90,000 shares at $5.25 per share and 135,000 shares at $7.00 per share. During 1994, 211,500 warrants were exercised to purchase common stock for $1,323,000. In 1995 and 1996, no warrants were exercised by EEP or EECIP.

In connection with an amendment and increase in the facility under the credit agreement with First Union and the extension of the due date on the term note, the Company granted stock warrants to First Union covering 424,000 shares of its common stock at an average price of $9.79 a share. The warrants are exercisable in whole or in part through December 1999 and are nontransferable without the consent of the Company.

At December 31, 1996, the Company has approximately 6,600,000 shares reserved for future issuance for conversion of its stock options, warrants, Rights, preferred stock, CVRs, and incentive plans for the Company's directors and employees.

9. 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 31	
	1995	1996
	(In thousands)	
Deferred tax liabilities:		
Full cost pool, including intangible drilling costs	$ 661	$ 34,298
State taxes	187	187
Other	101	61
Total deferred tax liabilities	949	34,546
Deferred tax assets:		
Depletion	242	431
Net operating losses	6,163	6,831
Other	13	12
Total deferred tax assets	6,418	7,274
Valuation allowance for deferred tax assets	(5,656)	(5,656)
Net deferred tax assets	762	1,618
Net deferred tax liabilities	$ 187	$ 32,928

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

	Current	Deferred
Federal	$ -	$ -
State	-	-
Foreign	176	-
	$ 176	$ -

At December 31, 1996, the Company had, subject to the limitations discussed below, $20,094,000 of net operating loss carryforwards for U.S. tax purposes, of which it is estimated a maximum of $17,562,000 may be utilized before it expires. These loss carryforwards will expire from 2002 through 2010 if not utilized. At December 31, 1996, the Company had approximately $830,000 of net operating loss carryforwards for Canadian tax purposes which expire in 2003.

As a result of the acquisition of certain partnership interests and crude oil and natural gas properties in 1990 and 1991, an ownership change under Section 382 of the Internal Revenue Code of 1986, as amended (Section 382), occurred in December 1991. Accordingly, it is expected that the use of the U.S. net operating loss carryforwards generated prior to December 31, 1991 of $4,909,000 will be limited to approximately $235,000 per year.

During 1992, the Company acquired 100% of the common stock of an unrelated corporation. The use of net operating loss carryforwards of $1,121,000 acquired in the acquisition are limited to approximately $115,000 per year.

As a result of the issuance of additional shares of common stock for acquisitions and sales of common stock, an additional ownership change under Section 382 occurred in October 1993. Accordingly, it is expected that the use of all net operating loss carryforwards generated through October 1993(including those subject to the 1991 and 1992 ownership changes discussed above) of $8,224,000 will be limited to approximately $1,034,000 per year, subject to the lower limitations described above. Of the $8,224,000 net operating loss carryforwards existing at October 1993, it is anticipated that the maximum net operating loss that may be utilized before it expires is $5,692,000. Future changes in ownership may further limit the use of the Company's carryforwards.

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 $5,656,000 and $5,657,000 for deferred tax assets at December 31, 1995 and 1996, respectively.

The reconciliation of income tax attributable to continuing operations computed at the U.S. federal statutory tax rates to income tax expense is:

	December 31		
	1994	1995	1996
	(In thousands)		
Tax (expense) benefit at U.S. statutory rates (34%)	$ (38)	$ 411	$ (743)
(Increase) decrease in deferred tax asset valuation allowance ..	31	(174)	(1)
Higher effective rate of foreign operations	-	-	(49)
Percentage depletion	-	-	189
Other	7	(237)	428
	$ -	$ -	$ (176)

10. Commitments and Contingencies

Operating Leases

During 1995, the Company entered into a noncancelable lease for new primary office space which, as amended, provides for payments of $15,700 per month through January 1998, $13,700 per month through March 2000, and $19,000 per month through March 2006, at which time the lease expires.

During the years ended December 31, 1994, 1995, and 1996, the Company incurred rent expense of approximately $108,000, $103,000, and $179,000, respectively. Future minimum rental payments are as follows at December 31, 1996:

1997	$ 300,000
1998	300,000
1999	300,000
2000	300,000
2001	340,000
Thereafter	970,000

Aggregate future minimum rentals to be received under noncancelable subleases as of December 31, 1996 amount to approximately $57,000.

Contingencies

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, 1996, 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's financial statements.

11. Discontinued Operations

In January 1995, the Company entered into a plan to discontinue the operations of its coal properties and commenced the permanent closing of the mine. As of December 31, 1994, the Company wrote off its investment in its coal properties and related equipment, eliminated the related minority interest in the coal entities, and established a liability of $150,000 pursuant to a plan to discontinue operations for future costs related to closing the mine. Additionally, during 1994 the Company sold its interest in Castle Minerals, Inc., which was acquired in 1992 to finance the coal operations, for $371,000, net of expenses related to the sale. The Company recorded a loss on these transactions in 1994 of $988,000. The revenues from coal sales for the years ended 1994 and 1995 were $104,310 and $-0-, respectively.

12. Quarterly Results of Operations (Unaudited)

Selected results of operations for each of the fiscal quarters during the years ended December 31, 1995 and 1996 are as follows:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Year Ended December 31, 1995				
Net revenue	$ 3,237	$ 3,402	$ 3,289	$ 3,889
Operating income	763	931	647	542
Net (loss)	(225)	(83)	(375)	(525)
Loss per common share	(.07)	(.04)	(.10)	(.13)
Year Ended December 31, 1996				
Net revenue	4,477	3,305	3,616	15,255
Operating income	1,486	365	744	6,231
Income (loss) before extraordinary item	599	(240)	(236)	1,817
Net income (loss)	599	(240)	(605)	1,759
Earnings (loss) per common share before extraordinary item	.08	(.06)	(.06)	.25
Earnings (loss) per common and common equivalent share	.08	(.06)	(.12)	.24

During the fourth quarter of 1996, the Company completed several acquisitions as described in Note 2 which effected net revenues, gross profit and net income.

Certain previously reported financial information has been reclassified to conform with the current presentation.

13. Benefit Plans

The Company has a defined contribution plan (401(k)) covering all eligible employees of the Company. No contributions were made by the Company during 1994 or 1995. During 1996, the Company contributed 2,500 shares of its common stock to the Plan and recorded the fair value of $12,500 as compensation expense. 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 overall contribution is limited to the lesser of 20% of the employee's annual compensation or $9,240.

In January 1995, the Company created the Technical Employees Incentive Bonus Plan, whereby technical employees have an incentive to find and develop crude oil and natural gas reserves on an economic basis beneficial to the Company and its shareholders. Participants are any technical employees (geologist, geophysicist, engineer) not covered by another incentive bonus plan. A participant may earn a monetary bonus of up to 65% of the participant's base salary each year. The bonuses are determined in the first quarter of each year and are based upon the amount of new proved developed producing reserves booked each year on approved exploration and exploitation projects taking into consideration the cost per equivalent barrel of developing the new reserves. During 1995 and 1996, the Company incurred no bonus expense.

14. Summary Financial Information of Canadian Abraxas Petroleum Ltd.

The following is summary financial information of Canadian Abraxas, a wholly owned subsidiary of the Company. Canadian Abraxas is jointly and severally liable for the entire balance of the Notes ($215,000,000), of which $84,612,000 was utilized by Canadian Abraxas in connection with the acquisition of CGGS. The Company has not presented seperate financial statements and other disclosures concerning Canadian Abraxas because management has determined that such information is not material to the holders of the Notes.

Assets	(In thousands)	Liabilities and Shareholder's Equity	
Total current assets	$ 6,174	Total current liabilities ...	$ 3,624
Oil and gas properties ..	115,671	11.5% Senior Notes due 2004 .	84,612
Other assets	3,302	Other liabilities	34,797
	$ 125,147	Shareholder's equity	2,114
			$ 125,147

Revenues	$ 3,972
Operating costs and expenses	(2,292)
Interest expense	(1,331)
Other income (expense)	23
Income tax	(175)
Net income	$ 197

15. Business Segments

The Company conducts its operations through two industry segments, the exploration for and the acquisition, development and production of crude oil and natural gas (E&P) and the processing of natural gas (Processing). The E&P segment acquires and explores for, develops, produces and markets crude oil, condensate natural gas liquids and natural gas. The Processing segment processes natural gas owned by third parties. The Company's significant E&P operations are located in the Texas Gulf Coast, the Permian Basin of west Texas, southwestern Wyoming and western Canada. The Processing segment engages in natural gas gathering and processing operations. Natural gas gathering operations involve locating and contracting for natural gas supplies produced from crude oil and natural gas fields and the operation and maintenance of a gathering system of pipelines that connect such natural gas supply sources to natural gas processing plants. Natural gas processing involves the custom processing of natural gas for third parties. Segment income excludes interest income, interest expense and unallocated general corporate expenses. 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 1996 seven customers accounted for approximately 66% of oil and natural gas production revenues and three customers accounted for approximately 54% of gas processing revenues. In 1995 and 1994 one customer accounted for approximately 20% and 35% of oil and natural gas production revenues, respectively.

Business segment information about the Company's 1996 operations in different industries is as follows:

	E&P	Processing	Total
		(In thousands)	
Revenues	$ 26,053	$ 600	$ 26,653
Operating profit	$ 8,737	$ 19	$ 8,756
General corporate expenses			(119)
Interest expense and amortization of deferred financing fees			(6,521)
Income from continuing operations before income taxes			$ 2,116
Identifiable assets	$ 253,707	$ 40,700	$ 294,407
Corporate assets			10,435
Total assets			$ 304,842

Depreciation and depletion for E&P and Processing was approximately $9,143,000 and $291,000, respectively. Capital expenditures for E&P and Processing were $145,600,000 and $27,300,000, respectively.

During 1994 and 1995 the Company's operations were entirely in the E&P segment.

Business segment information about the Company's 1996 operations in different geographic areas is as follows:

	U.S.	Canada	Total
	(In thousands)		
Revenues	$ 21,999	$ 4,654	$ 26,653
Operating profit	$ 7,062	$ 1,694	$ 8,756
General corporate expenses			(119)
Interest expense and amortization of deferred financing fees			(6,521)
Income from continuing operations before income taxes			$ 2,116
Identifiable assets at December 31, 1996	$ 168,141	$ 126,266	$ 294,407
Corporate assets			10,435
Total assets			$ 304,842

During 1994 and 1995 the Company's operations were entirely in the United States.

16. Commodity Swap Agreements

The Company enters into commodity swap agreements (Hedge Agreements) to reduce its exposure to price risk in the spot market for crude oil and natural gas. Pursuant to the Hedge Agreements, either the Company or the counterparty thereto is required to make payment to the other at the end of each month. During the period from March 1996 through November 1996, payments were exchanged equal to the product of 5,000 MMBtu (million Btu's) of natural gas per day and the difference between a specified fixed price and a variable price for natural gas based on the arithmetic average of the last three trading days' settlement price quoted for natural gas contracts on the New York Mercantile Exchange (NYMEX). This Hedge Agreement provided for the Company to make payments to the counterparty to the extent that the market price exceeds the fixed price of $1.747 per MMBtu (thousand Btu's) and for the counterparty to make payments to the Company to the extent the market price was less than $1.747 per MMBtu. A loss of $511,000 was incurred during the period of hedged production.

In November 1996, the Company assumed Hedge Agreements extending through October 2001 with a counterparty involving the following notional quantities and fixed prices:

	Crude Oil		Natural Gas	
	Notional Quantity per Month (barrels)	Fixed Price (barrel)	Notional Quantity per Month (MMBtu)	Fixed Price (MMBtu)
1996	20,060	$ 17.53	87,406	$ 1.925
1997	15,810	$ 17.20	53,712	$ 1.797
1998	13,175	$ 17.20	36,601	$ 1.793
1999	11,050	$ 17.47	24,489	$ 1.820
2000	9,180	$ 17.78	18,794	$ 1.872
2001	8,160	$ 18.08	14,850	$ 1.902

These Hedge Agreements provide for the Company to make payments to the counterparty to the extent the market prices determined based on the price for west Texas intermediate light sweet crude oil on the NYMEX for crude oil and the Inside FERC, Tennessee Gas Pipeline Co.; Texas (Zone O) price for natural gas exceeds the above fixed prices and for the counterparty to make payments to the Company to the extent the market prices are less than the above fixed prices. The Company accounts for the related gains or losses (a loss of $453,000 in 1996) in crude oil and natural gas revenue in the period of the hedged production. The average notional quantity of crude oil and natural gas under the Hedge Agreements each month for 1997 is equal to approximately 19% and .5%, respectively, of the Company's expected monthly production for 1997 based on the Company's January 1, 1997 reserve reports. At December 31, 1996, the estimated fair market value of the Hedge Agreements is a loss of $2,460,000.

In January 1997, the Company effectively collared its crude oil prices between $19.00 and $25.60 per barrel on 1,000 barrels per day from February 1997 through December 1997.

17. Subsequent Event

On January 31, 1997 the Company sold its interest in its crude oil and natural gas property, plant, and equipment in the Hoole area in Alberta, Canada for approximately $9,300,000.

18. Supplemental Oil and Gas Disclosures (Unaudited)

The accompanying table presents information concerning the Company's crude oil and natural gas producing activities as required by Financial Accounting Standards 69, "Disclosures about Oil and Gas Producing Activities." Capitalized costs relating to oil and gas producing activities are as follows:

	December 31	
	1995	1996
	(In thousands)	
Proved crude oil and natural gas properties	$ 104,127	$ 231,090
Unproved properties	--	37,268
Total	104,127	268,358
Accumulated depreciation, depletion, and amortization, and valuation allowances ..	(29,651)	(38,368)
Net capitalized costs	$ 74,476	$ 229,990

Costs incurred in oil and gas property acquisitions, exploration and development activities are as follows:

	Years Ended December 31								
	1994			1995			1996		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)								
Property acquisition costs:									
Proved	$ 33,597	$ 33,597	$ --	$ 719	$ 719	$ --	$ 87,005	$ 37,609	$ 49,396
Unproved	5	5	--	--	--	--	37,268	8,230	29,038
	$ 33,602	$ 33,602	$ --	$ 719	$ 719	$ --	$124,273	$ 45,839	$ 78,434
Property development and exploration costs	$ 7,151	$ 7,151	$ --	$ 11,398	$ 11,398	$ --	$ 18,133	$ 18,115	$ 18

The results of operations for oil and gas producing activities are as follows:

	Years Ended December 31								
	1994			1995			1996		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
	(In thousands)								
Revenues	$ 11,114	$ 11,114	$ -	$ 13,660	$ 13,660	$ -	$ 25,749	$ 21,758	$ 3,991
Production costs	(3,693)	(3,693)	-	(4,333)	(4,333)	-	(5,858)	(5,193)	(665)
Depreciation, depletion, and amortization	(3,777)	(3,777)	-	(5,313)	(5,313)	-	(9,103)	(7,695)	(1,408)
General and administrative .	(202)	(202)	-	(261)	(261)	-	(483)	(401)	(82)
Income taxes	-	-	-	-	-	-	(148)	-	(148)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ 3,442	$ 3,442	$ -	$ 3,753	$ 3,753	$ -	$ 10,157	$ 8,469	$ 1,688
Depletion rate per barrel of oil equivalent	$ 4.35	$ 4.35	$ -	$ 4.67	$ 4.67	$ -	$ 5.12	$ 5.10	$ 5.29

Estimated Quantities of Proved Oil and Gas Reserves

The following table presents the Company's estimate of its net proved crude oil and natural gas reserves as of December 31, 1994, 1995, and 1996. The Company's management emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. The estimates have been prepared by independent petroleum reserve engineers.

	Total		United States		Canada	
	Liquid Hydrocarbons	Natural Gas	Liquid Hydrocarbons	Natural Gas	Liquid Hydrocarbons	Natural Gas
	(Barrels)	(Mcf)	(Barrels)	(Mcf)	(Barrels) (In Thousands)	(Mcf)
Proved developed and undeveloped reserves:						
Balance at December 31, 1993	4,086	16,591	4,086	16,591	-	-
Revisions of previous estimates	854	5,034	854	5,034	-	-
Extensions and discoveries	2,268	15,062	2,268	15,062	-	-
Purchase of minerals in place	2,417	33,288	2,417	33,288	-	-
Production	(469)	(2,393)	(469)	(2,393)	-	-
Sale of minerals in place	-	(3)	-	(3)	-	-
Balance at December 31, 1994	9,156	67,579	9,156	67,579	-	-
Revisions of previous estimates	(1,328)	(18,941)	(1,328)	(18,941)	-	-
Extensions and discoveries	1,335	6,819	1,335	6,819	-	-
Purchase of minerals in place	214	2,889	214	2,889	-	-
Production	(544)	(3,553)	(544)	(3,553)	-	-
Sale of minerals in place	(566)	(224)	(566)	(224)	-	-
Balance at December 31, 1995	8,267	54,569	8,267	54,569	-	-
Revisions of previous estimates	680	(2,561)	680	(2,561)	-	-
Extensions and discoveries	1,752	10,194	1,746	10,060	6	134
Purchase of minerals in place	8,062	121,408	6,694	65,135	1,368	56,273
Production	(724)	(6,350)	(670)	(5,042)	(54)	(1,308)
Sale of minerals in place	(2)	-	(2)	-	-	-
Balance at December 31, 1996	18,035	177,260	16,715	122,161	1,320 (1)	55,099

(1) Includes 120,400 barrels of crude oil reserves owned by Cascade of which 57,600 barrels are applicable to the minority interest's share of these reserves.

Estimated Quantities of Proved Oil and Gas Reserves (continued)

	Total		United States		Canada	
	Liquid Hydrocarbons	Natural Gas	Liquid Hydrocarbons	Natural Gas	Liquid Hydrocarbons	Natural Gas
	(Barrels)	(Mcf)	(Barrels)	(Mcf)	(Barrels)	(Mcf)
					(In Thousands)	
Proved developed reserves:						
December 31, 1994	5,701	48,973	5,701	48,973	-	-
December 31, 1995	6,000	44,026	6,000	44,026	-	-
December 31, 1996	14,961	157,660	13,641	103,639	1,320	54,021

The significant upward revision in 1994 of previous liquid hydrocarbons and natural gas was due principally to increased estimates of recoverable reserves in existing wells as a result of drilling and workover success in 1994, combined with the completion of geological engineering studies on several major fields.

The significant downward revision in 1995 of previous liquid hydrocarbons and natural gas was due principally to decreased estimates of recoverable reserves in existing wells related to disappointing drilling results principally in the East White Point Field, resulting in reclassification of proved undeveloped reserves to probable reserves.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following disclosures concerning the standardized measure of future cash flows from proved crude oil and natural gas reserves are presented in accordance with Statement of Financial Accounting Standards No. 69. The standardized measure does not purport to represent the fair market value of the Company's proved crude oil and natural gas reserves. An estimate of fair market value would also take into account, among other factors, the recovery of reserves not classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Under the standardized measure, future cash inflows were estimated by applying period-end prices at December 31, 1996, adjusted for fixed and determinable escalations, to the estimated future production of year-end proved reserves. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's basis in the associated proved crude oil and natural gas properties, less the tax basis of the properties. Operating loss carryforwards, tax credits, and permanent differences to the extent estimated to be available in the future were also considered in the future income tax calculations, thereby reducing the expected tax expense.

Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Set forth below is the Standardized Measure relating to proved oil and gas reserves for:

	Years Ended December 31								
	1994			1995			1996		
	Total	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada
							(In thousands)		
Future cash inflows	$ 238,028	$ 238,028	$ -	$ 243,969	$ 243,969	$ -	$ 1,009,420	$ 824,776	$184,644
Future production and development costs	(84,552)	(84,552)	-	(79,910)	(79,910)	-	(251,749)	(201,498)	(50,251)
Future income tax expense	(26,542)	(26,542)	-	(28,015)	(28,015)	-	(207,834)	(157,508)	(50,326)
Future net cash flows	126,934	126,934	-	136,044	136,044	-	549,837	465,770	84,067
Discount	(49,241)	(49,241)	-	(48,884)	(48,884)	-	(220,016)	(193,221)	(26,795)
Standardized Measure of discounted future net cash relating to proved reserves	$ 77,693	$ 77,693	$ -	$ 87,160	$ 87,160	$ -	$ 329,821	$ 272,549	$ 57,272

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is an analysis of the changes in the Standardized Measure:

	Year Ended December 31		
	1994	1995	1996
	(In thousands)		
Standardized Measure, beginning of year	$ 32,929	$ 77,693	$ 87,160
Sales and transfers of oil and gas produced, net of production costs	(7,421)	(9,351)	(19,887)
Net changes in prices and development and production costs from prior year	2,450	22,560	65,917
Extensions, discoveries, and improved recovery, less related costs	13,509	13,475	30,699
Purchases of minerals in place	29,163	3,867	244,930
Sales of minerals in place	(2)	(3,355)	(24)
Revision of previous quantity estimates	7,346	(24,937)	2,257
Change in future income tax expense	5,804	382	(87,393)
Other	(9,377)	(943)	(2,554)
Accretion of discount	3,292	7,769	8,716
Standardized Measure, end of year	$ 77,693	$ 87,160	$ 329,821

SIGNATURES

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

ABRAXAS PETROLEUM CORPORATION

By: /s/ Robert L.G. Watson	By: /s/ Chris Willford
Robert L.G. Watson, President and Principal Executive Officer	Chris Williford, Executive Vice President and Principal Financial and Accounting Officer

DATED:

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

Signature	Name and Title	Date
/s/ Robert L.G. Watson Robert L.G. Watson	Chairman of the Board, President (Principal Executive Officer) and Director	3/28/97
/s/ Chris Williford Chris Williford	Exec. Vice President and Treasurer (Principal Financial and Accounting Officer) and Director	3/28/97
/s/ Franklin Burke Franklin Burke	Director	3/28/97
/s/ Robert D. Gershen Robert D. Gershen	Director	3/28/97
/s/ Richard M. Kleberg, III Richard M. Kleberg, III	Director	3/28/97
/s/ Harold Carter Harold Carter	Director	3/28/97
/s/ James C. Phelps James C. Phelps	Director	3/28/97
/s/ Paul A. Powell, Jr. Paul A. Powell, Jr.	Director	3/28/97
/s/ Richard M. Riggs Richard M. Riggs	Director	3/28/97

Exhibit (11) - Statement Re:
Computation of Earnings Per Share

	Year Months Ended December 31		
	1996	1995	1994
Primary:			
Average shares outstanding	5,757,105	4,635,412	4,309,878
Net effect of dilutive stock options and warrants based on the treasury stock method using average market price	24,277	-- (1)	-- (1)
Assumed issuance under existing Contingent Value Rights agreement	1,013,060	-- (1)	-- (1)
Totals	6,794,442	4,635,412	4,309,878
Net Income (loss)	$1,147,525	$(1,574,428)	$(2,278,000)
Per share amount	$ .17	$ (.34)	$ (.60)
Fully diluted:	5,757,105	4,635,412	4,309,878
Average shares outstanding			
Net effect of dilutive stock options and warranrsbased on the Treasury Stock method using the year-end market price	176,569	-- (1)	-- (1)
Assumed issuance under existing Contingent Value Rights agreement	1,013,060	-- (1)	-- (1)
Assumed conversion of convertible preferred stock	-- (1)	-- (1)	-- (1)
Totals	6,946,734	4,635,412	4,309,878
Net income (loss)	$1,147,525	$(1,574,428)	$(2,578,000)
Per share amount	$ .17	$ (.34)	$ (.60)

(1) Net effect if stick options, and warrants and convertible preferred stock are not included because the effect is antidilutive.

Exhibit 23.1

Consent of Independent Auditors

We consent to the incorporation by reference in the Registration Statements (Form S-8 No. 33-48932) pertaining to Abraxas Petroleum Corporation 1984 Non-Qualified Stock Option Plan; (Form S-8 No. 33-48934) pertaining to Abraxas Petroleum Corporation 1984 Incentive Stock Option Plan; (Form S-8 No. 33-72268) pertaining to the Abraxas Petroleum Corporation 1993 Key Contribution Stock Option Plan; (Form S-8 No. 33-81416) pertaining to the Abraxas Petroleum Corporation Restricted Share Plan for Directors; (Form S-8 No. 33-81418) pertaining to Abraxas Petroleum Corporation 1994 Long Term Incentive Plan; (Form S-8 No. 333-17375) pertaining to the Abraxas Petroleum Corporation Director Stock Option Plan; (Form S-8 No. 333-17377) pertaining to the Abraxas Petroleum Corporation 401 (K) Profit Sharing Plan; and (Form S-3 No. 333-398) of Abraxas Petroleum Corporation and the related Prospectus of our report dated March 21, 1997, with respect to the consolidated financial statements of Abraxas Petroleum Corporation and subsidiaries included in this Annual Report (Form 10-K) for the year ended December 31, 1996.

Ernst & Young LLP

San Antonio, Tx
March 21, 1997

Exhibit 23.2

Consent of independent, third party, Petroleum Engineers

Degolyer and MacNaughton
One Energy Square
Dallas, TX 75206

March 25, 1996

Abraxas Petroleum Corporation
500 N. Loop 1604 E., Suite 100
San Antonio, TX 78232

Gentlemen:

We hereby consent to the incorporation in your Annual Report on Form 10-K of the references to DeGolyer and MacNaughton in the "Reserves Information" section on page 20 and to the use by reference of information contained in our "Appraisal Report as of December 31, 1996 on Certain Interests owned by Abraxas Petroleum Corporation US Properties," in our "Appraisal Report as of December 31, 1996 on Certain Interests owned by Abraxas Petroleum Corporation Canadian Properties," and in our "Appraisal Report as of December 31, 1996 on Certain Interests owned by Abraxas Petroleum Corporation All Properties," provided, however, that since the crude oil and condensate reserves estimates, as of December 31, 1996, set forth in these Reports have been combined with reserves estimates of other petroleum consultants, we are necessarily unable to verify the accuracy of the crude oil and condensate reserves values contained in the aforementioned Annual Report.

Very truly yours,

DeGolyer and MacNaughton

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