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 (FEE REQUIRED)

For the fiscal year ended December 31, 1996

{ } TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D)
OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)

For the transaction period from _______ to _______
COMMISSION FILE NUMBER 0-9592

LOMAK PETROLEUM, INC.
(Exact name of registrant as specified in its charter)

DELAWARE	34-1312571
(State of incorporation)	(I.R.S. Employer Identification No.)

500 THROCKMORTON STREET, FT. WORTH, TEXAS	76102
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (817) 870-2601

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

Securities registered pursuant to Section 12(g) of the Act:

COMMON STOCK, $.01 PAR VALUE
PREFERRED STOCK, $1 PAR VALUE
(Title of class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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. {X}

The aggregate market value of voting stock of the Registrant held by non-affiliates (excluding voting shares held by officers and directors) was $398,718,000 on March 17, 1997.

Indicate the number of shares outstanding of each of the Registrant's classes of stock on March 17, 1997: Common Stock $.01 par value: 20,272,242; Preferred Stock $1 par value: 1,150,000.

DOCUMENTS INCORPORATED BY REFERENCE:

Part III of this report incorporates by reference the Registrant's Proxy Statement relating to the Registrant's 1997 Annual Meeting of Stockholders.

LOMAK PETROLEUM, INC.

ANNUAL REPORT ON FORM 10-K
YEAR ENDED DECEMBER 31, 1996

PART I

ITEM 1. BUSINESS

GENERAL

Lomak Petroleum, Inc. ("Lomak" or the "Company") is an independent oil and gas company engaged in the development, exploration and acquisition of oil and gas properties in the United States. Lomak's core areas of operation are located in Midcontinent, the Gulf Coast and Appalachia. The Company has grown through a combination of development, exploration and acquisition activities. Since January 1, 1991, 62 acquisitions have been consummated at a total cost of approximately $250 million and approximately $40 million has been expended on development and exploration activities. As a result, reserves and production have each grown during this period at a rate in excess of 69% per annum. At December 31, 1996, proved reserves totaled 384 Bcfe, having a pre-tax present value at constant prices of $492 million and a reserve life of nearly 14 years.

At December 31, 1996, Lomak held interests in 6,761 gross (5,187 net) productive oil and gas wells. The Company currently operates over 6,500 wells which account for more than 95% of its developed reserves. In addition, the Company owns and operates approximately 1,900 miles of gas gathering systems in proximity to its principal gas properties. The Company also provides oil field services, including brine disposal and various well services primarily for certain of its own properties. The operations of the Company are considered to fall within a single industry segment; the exploration for, development and production of crude oil and natural gas.

The Company recently acquired oil and gas properties located in West Texas, South Texas and the Gulf of Mexico (the "Cometra Properties") from American Cometra, Inc. ("Cometra") for a purchase price of $385 million (the "Cometra Acquisition"). On a pro forma basis, the Cometra Acquisition increases the Company's proved reserves at December 31, 1996 by 68% to 644 Bcfe and increased its Present Value by 98% to $974 million. The Cometra Properties, located primarily in the Company's core operating areas, include 515 producing wells, 401 proven development projects and substantial additional development and exploration potential on approximately 150,000 gross acres (90,000 net acres). In addition, the Cometra Properties include 265 miles of gas pipelines, a 25,000 Mcf/d gas processing plant and an above-market gas contract with a major Texas gas utility covering approximately 30% of the December 1996 production from the Cometra Properties. Forward looking statements included hereafter will include the effects of the Cometra Acquisition.

The Company's common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "LOM". During 1996, trading volume averaged 117,600 shares per day. The Company maintains its corporate headquarters at 500 Throckmorton Street, Fort Worth, Texas 76102 and its telephone number is (817) 870-2601.

DESCRIPTION OF THE BUSINESS

Strategy

The Company's objective is to continue to increase its asset base, cash flow and earnings through a balanced strategy of development, exploration and acquisition activities in core operating areas. In each core area, the Company establishes separate acquisition, engineering, operating, geological and other technical expertise. The Company currently has core operating areas in Midcontinent, the Gulf Coast and Appalachia. Through its strategy, the Company does not depend solely on any one region or activity to grow its asset base. In addition, by operating in three core areas, the Company has expanded its development, exploration and acquisition opportunities.

Development. The Company's development activities include recompletions of existing wells, infield drilling and installation of secondary recovery projects. Development projects are generated within core operating areas where the Company has significant operational and technical experience. At December 31, 1996, including the effect of the Cometra Acquisition, over 1,100 proven development projects were in inventory. These projects are geographically diverse, vary between oil and gas, and are balanced with regard to risk. Between 175 and 200 of these projects are expected to be initiated in 1997 at a total cost of approximately $45 million. Based on the number of projects currently in inventory, development expenditures are currently projected to approximate $130 million for the next three years.

Exploration. Historically, the Company's drilling activities concentrated on development drilling in its core operating areas. Beginning in 1994, the Company began participating in exploration projects in less developed or lightly explored formations within its core operating areas. The Company has an inventory of nearly 300 moderate risk/moderate reward exploitation drilling opportunities, as well as higher risk/higher reward exploration projects. The Company's existing inventory of exploration projects and leads varies in risk and reward based on their depth, location and geology. Lomak has identified 250 exploitation drilling projects principally consisting of step-out drilling from existing proved or proved undeveloped locations. Current exploration projects target deeper horizons within existing Company-operated fields, as well as establishing new fields in exploration trend areas in which Lomak's technical staff has experience. Lomak's strategy is based upon limiting its risk by allocating no more than 10% of its cash flow to higher risk exploration activities and by participating in a variety of projects with differing characteristics. The Company projects exploitation and exploratory expenditures to range between $6 million and $7 million in 1997 and currently estimates that it will spend $25 million on exploitation activities and $20 million on exploration activities over the next three years.

Acquisitions. Since January 1, 1991, including the Cometra Acquisition, 63 acquisitions have been completed for a total consideration of $635 million. Approximately 719 Bcfe of proved reserves have been acquired at an average cost of $.74 per Mcfe. The Company's acquisition strategy has historically been based on: (i) Locale: focusing in areas containing many small oil and gas operators and where larger companies are no longer active; (ii) Efficiency: targeting acquisitions in which operating and cost efficiencies can be obtained; (iii) Reserve Potential: pursuing properties with the potential for reserve increases through recompletions and drilling; (iv) Incremental Purchases: seeking acquisitions where opportunities for purchasing additional interests in the same or adjoining properties exist; and (v) Complexity: pursuing more complex but less competitive corporate or partnership acquisitions.

Development Activities

The Company's development activities include recompletions of existing wells, infill drilling and installation of secondary recovery projects. Development projects are generated within core operating areas where the Company has significant operational and technical expertise. Currently, as described below, the Company has 1,163 proven development projects in inventory. These projects are geographically diverse, vary between oil and gas and are balanced with regard to risk. The following table sets forth information pertaining to the Company's proven development inventory at December 31, 1996.

PROVEN DEVELOPMENT INVENTORY

	NUMBER OF PROJECTS		
	RECOMPLETIONS	DRILLING LOCATIONS	TOTAL
Midcontinent Region			
Permian Basin	85	129	214
Val Verde Basin	76	134	210
Anadarko Basin	117	86	203
San Juan Basin	18	29	47
Subtotal	296	378	674
Appalachian Region	43	320	363
Gulf Coast Region	79	47	126
Total	418	745	1,163

The Company currently anticipates that it will initiate 175 to 200 development projects in 1997. Assuming that 200 projects are initiated per year, the Company currently has more than a five year inventory of proven development projects. Lomak expects to spend approximately $130 million over the next three years for development.

Exploration Activities

The Company has an inventory of nearly 300 moderate risk/moderate reward exploitation drilling opportunities, as well as higher risk/higher reward exploration projects. Lomak has identified 250 exploitation drilling projects, principally consisting of step-out drilling from existing proved or proved undeveloped locations. Current exploration projects target deeper horizons within existing Company-operated fields, as well as establishing new fields in exploration trend areas in which Lomak's technical staff has experience. The Company has not previously, and does not currently, plan to participate in wildcat exploratory drilling outside its core operating areas.

Lomak's strategy is based on limiting its risk by allocating no more than 10% of its cash flow to higher risk exploration activities and by participating in a variety of projects with differing characteristics. The Company's existing inventory of exploration projects and leads varies in risk and reward based on their depth, location and geology. A significant portion of the existing, as well as future, exploration projects will be enhanced by use of advanced technology including 3-D seismic and improved completion techniques.

In each of its core operating areas, the Company's geological and geophysical staff generate both exploitation and exploration projects with the assistance of the Company's reservoir engineers, landmen and production engineers. The Company currently estimates that it will spend $25 million on exploitation activities and $20 million on exploration activities over the next three years. Existing exploitation and exploration project inventory is described below.

Midcontinent. Exploitation projects in the Midcontinent region include 116 infill or step-out drilling locations on leasehold acreage held by currently producing wells adjacent to the Company's production in the Sterling area of the Permian Basin, as well as 134 infill or step-out locations on leasehold acreage held by currently producing wells primarily in the Oakridge and Francis Hill Fields in the Val Verde Basin. In the Big Lake area of the Permian Basin, the Company is conducting an analysis to determine the potential for recovery of additional reserves through increased density drilling. Based on the initial results of the study, the Company believes there is potential for 200 economic drill sites on its Big Lake area acreage. Current exploration projects include deeper drilling to the Ellenburger and Fussleman formations in the Permian and Val Verde Basins. Several projects targeting the Red Fork, Morrow and Hunton formations are in various stages of development in the Anadarko Basin. In the San Juan Basin, the Company's acreage holds exploration potential for production from the Pictured Cliffs, Gallup and Dakota formations.

Appalachia. In the Appalachian region, the Company has identified approximately 100 infill or step-out drilling projects on existing leasehold acreage. In addition, the Company has identified several hundred additional potential locations near Company-owned gathering systems on acreage the Company believes will be available for leasing in the future. The Company believes that the location of its pipelines will provide it with a competitive advantage in leasing this acreage, which is currently unleased. These locations target the blanket Clinton and Medina sandstones. Exploration activity in Appalachia centers around the drilling of deeper formations from leasehold acreage generally being held by existing production from shallower production. The targeted formations are in the Knox Sequence trend, which includes the Rose Run, Beekmantown and Trempealeau formations. Lomak currently owns leasehold acreage aggregating over 250,000 net acres in the Knox Sequence trend area. With the assistance of higher quality 2-D seismic as well as 3-D seismic, Lomak believes the Knox Sequence trend area could generate substantial reserves over the next five years.

Gulf Coast. Exploitation projects in the Gulf Coast region include 34 infill or step-out drilling locations for the Yegua and Frio formations in South Texas and the Wilcox and Carrizo formations in East Texas. Deeper, higher risk exploratory projects have been generated in South Texas targeting the Wilcox and Vicksburg formations. On the offshore properties, 11 exploitation and exploration projects have been identified to the Lenticulina and Marginulina sands. There are four exploration projects targeting the Taylor sand of the Cotton Valley formation in East Texas.

Acquisition Activities

The following table sets forth information pertaining to acquisitions completed during the period January 1, 1991 through December 31, 1996 (including the Cometra Acquisition).

Period	Number of Transactions	Purchase Price (1) (In thousands)	MMcfe Acquired	Cost per Mcfe (2)
1991	9	$ 11,189	14,602	$ 0.75
1992	7	6,884	12,513	0.41
1993	12	40,527	64,552	0.59
1994	17	63,354	92,851	0.67
1995	9	71,074	103,849	0.61
1996	9	441,812	369,986	0.84
Total	63	$ 634,840	658,353	$ 0.74

(1) Includes purchase price for proved reserves as well as other acquired assets, including gas gathering lines, undeveloped leasehold and field service assets.

(2) Includes purchase price for proved reserves only. For the Cometra Acquisition, the purchase price for proved reserves includes the amount attributable to the above-market gas contract. If the cost per Mcfe was adjusted for the above-market gas contract, the 1996 cost per Mcfe would be reduced from $0.84 to $0.74 and the total cost per Mcfe would be reduced from $0.74 to $0.69.

Recent Significant Acquisitions

In addition to the Cometra Acquisition, the Company completed a number of significant acquisitions in 1995 and 1996 as described below. See "Cometra Acquisition" for a description of the Cometra Acquisition.

Bannon Interests. In April 1996, the Company acquired interests in approximately 270 producing wells and 108 proven recompletion and development drilling opportunities for $37.0 million. After giving effect to a subsequent sale of certain Rocky Mountain region interests for $6.5 million, the acquired properties were estimated to contain approximately 71 Bcfe of proved reserves. Also included were 17,300 net undeveloped acres located in east and south Texas.

Red Eagle Resources Corporation. Through a series of transactions effected in late 1994 and early 1995, the Company acquired Red Eagle Resources Corporation for $29.6 million in cash and $16.9 million of Common Stock. Red Eagle's assets included interests in approximately 370 producing wells located primarily in the Okeene Field of Oklahoma's Anadarko Basin. Subsequently, the Company acquired additional interests in over 100 Red Eagle wells for $3.9 million.

Eastern Petroleum Company. In January 1996, the Company acquired proved oil and gas reserves and 40 miles of gas gathering lines in Ohio for $13.7 million. In the second quarter of 1996, the Company initiated a program extending purchase offers to other interest owners in these properties. Through September 30, 1996, interests in 61 wells had been purchased for approximately $100,000.

Transfuel Interests. In September 1995, the Company acquired proved oil and gas reserves, 1,100 miles of gas gathering lines and 175,000 undeveloped acres in Ohio, Pennsylvania and New York from Transfuel, Inc. for $21.0 million.

Parker & Parsley Interests. In August 1995, the Company purchased proved oil and gas reserves, 300 miles of gas gathering lines and 16,400 undeveloped acres in Pennsylvania and West Virginia from Parker & Parsley Petroleum Company for $20.2 million.

Cometra Acquisition

GENERAL

The Company recently acquired the Cometra Properties for a purchase price of $385 million, consisting of $355 million in cash and 1,410,106 shares of Common Stock. The Company financed the cash portion of the purchase price with $221 million of borrowings under the Credit Agreement and the issuance to Cometra of a $134 million non-interest bearing promissory note due March 31, 1997, which is secured by a bank letter of credit. As a result of the Cometra Acquisition, the Company has significantly expanded its inventory of both development and exploration projects, increased its proved reserves at December 31, 1996 by 68% to 644 Bcfe and increased the Company's Present Value at December 31, 1996 by 98% to $974 million. On March 14, 1997, $186.1 million of the bank borrowings were repaid through the issuance of 4 million shares of Common Stock and $125 million of Senior Subordinated Notes.

COMETRA PROPERTIES

The Cometra Properties include 150,000 gross acres (90,000 net) located within the Company's core operating areas in West Texas, South Texas and the Gulf of Mexico. Netherland, Sewell & Associates, Inc., independent petroleum consultants, estimated that at December 31, 1996, the Cometra Properties had proved reserves of 202 Bcf of gas and 9.7 Mmbbls of oil with a Present Value of $481 million. In December 1996, the Cometra Properties produced at a rate of 66 Mmcfe/d through 515 wells. The Cometra Properties include 265 miles of gas pipelines and a 25,000 Mcf/d capacity gas processing plant.

The West Texas properties are located in the Val Verde and Permian Basins and account for 81% of the acquired reserves on a Present Value basis. The South Texas/Gulf of Mexico properties account for 19% of the acquired reserves on a Present Value basis. All of the Cometra Properties, except for the Gulf of Mexico properties, are within the Company's existing core operating areas. As a result, the Company expects to be able to quickly integrate the properties and begin exploitation activities. To facilitate the integration, the Company plans to offer positions to substantially all of Cometra's field and technical staff associated with these properties.

On a Present Value basis, 95% and 70%, respectively, of the West Texas and South Texas/Gulf of Mexico properties are operated by the Company. The offshore properties are operated by experienced third parties. Although the Company has no definitive plans to do so at this time, the Company has previously announced that it may elect to sell all or part of the Gulf of Mexico properties because they are not located in the Company's core areas.

RESERVES

The following table sets forth summary information with respect to the proved reserves of the Cometra Properties by region at December 31, 1996:

	Present Value				
	Amount (In thousands)	%	Oil & NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equiv. (Mmcfe)
West Texas....................	$387,852	81%	8,271	174,339	223,965
South Texas/Gulf of Mexico....	93,639	19	1,459	27,667	36,422
Total....................	$481,491	100%	9,730	202,006	260,387

The West Texas properties consist of 450 producing wells on 99,000 gross acres (70,000 net) located principally in the Val Verde and Permian Basins. The Company operates 95% of the properties on a Present Value basis and the pipelines and gas processing plant. Existing production ranges in depth from 3,000 to 7,000 feet. The Company has identified 365 proven recompletion and development drilling projects in this area. In the Val Verde Basin, the Company benefits from a $3.70 per Mcf gas sales contract covering 20,000 acres currently producing approximately 20,000 Mcf/d. The contract is with a large gas utility and expires in June 2000.

The South Texas/Gulf of Mexico properties consist of 65 producing wells on 51,000 gross acres (20,000 net). The Company operates 70% of the properties on a Present Value basis, primarily in South Texas. The Gulf of Mexico properties include 14 producing wells on seven offshore platforms, all of which are operated by third parties, including affiliates of National Fuel Gas Co., Noble Affiliates, Inc. and British Borneo Petroleum Syndicate plc. Total net daily production from the South Texas/Gulf of Mexico properties currently is 22,300 Mcfe. Onshore, production comes from depths ranging from 1,000 to 12,000 feet, and has an estimated reserve life in excess of seven years. In the Gulf of Mexico, production ranges in depth from 8,000 to 14,000 feet, while water depths vary from 50 to 220 feet. The Company has identified a total of 36 development projects. Both shallower and deeper horizons hold potential exploration opportunities, which the Company expects to evaluate further with the assistance of 3-D seismic technology.

GAS PLANT AND PIPELINES

As part of the Cometra Acquisition, the Company has acquired 265 miles of gas pipelines and a 25,000 Mcf/d capacity gas processing plant in the Permian Basin. The gas plant, located outside Sterling City, Texas, was constructed in 1995 and is currently processing gas, approximately 50% of which is attributable to Company operated wells, at the rate of 20,000 Mcf/d. The Company believes that the plant's capacity could be expanded to 35,000 Mcf/d for an additional capital expenditure of approximately $4.0 million.

Production

Production revenue is generated through the sale of oil and gas from properties held directly and through partnerships and joint ventures. Additional revenue is received from royalties. While oil and gas production is sold to a limited number of purchasers, none accounts for more than 10% of oil and gas revenues, it is believed that the loss of any one of them would not have a material adverse effect on the business. Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the ability to market production. While the Company anticipates an upward trend in energy prices, factors outside its control such as political developments in the Middle East, overall energy supply, weather conditions and economic growth rates have had, and may continue to have, an unpredictable effect on energy prices.

The following table sets forth historical revenue and expense information for the periods indicated (in thousands, except average sales price and operating cost data).

	Year Ended December 31,				
	1992	1993	1994	1995	1996
Production					
Oil (Bbl)	199	318	640	913	1,068
Gas (Mcf)	1,796	2,590	6,996	12,471	21,231
Mcfe (a)	2,990	4,498	10,836	17,949	27,641
Revenues					
Oil	$ 3,660	$ 5,118	$ 9,743	$15,133	$20,425
Gas	4,043	6,014	14,718	22,284	47,629
Total	$ 7,703	$11,132	$24,461	$37,417	$68,054
Average Sales Price					
Oil (Bbl)	$ 18.40	$ 16.07	$ 15.23	$ 16.57	$ 19.12
Gas (Mcf)	$ 2.25	$ 2.32	$ 2.10	$ 1.79	$ 2.24
Mcfe (a)	$ 2.58	$ 2.47	$ 2.26	$ 2.08	$ 2.46
Average Operating Cost					
Per Mcfe	$ 0.99	$ 0.98	$ 0.93	$ 0.83	$ 0.88

(a) Oil is converted to Mcfe at a rate of 6 Mcf per barrel.

On a Mcfe basis, approximately 77% of 1996 production was natural gas. Gas production was sold to utilities, brokers or directly to industrial users. Gas sales are made pursuant to various arrangements ranging from month-to-month contracts, one year contracts at fixed or variable prices and contracts at fixed prices for the life of the well. All contracts other than the fixed price contracts contain provisions for price adjustment, termination and other terms customary in the industry. A number of the Appalachian gas contracts hold favorable sales prices when compared to spot market prices. Oil is sold on a basis such that the purchaser can be changed on 30 days notice. The price received is generally equal to a posted price set by the major purchasers in the area. Oil purchasers are selected on the basis of price and service. In 1996, revenues from oil and gas production amounted to $68.1 million, representing 75% of revenues. Oil and gas revenues for 1996 increased 82% over 1995.

Field Services

The field services area is comprised of three components -- well operations, brine disposal and well servicing. As of December 31, 1996, Lomak acted as operator of, or provided pumping services for, over 6,500 wells. For its well operations, the Company receives a monthly fee plus reimbursement of third party charges. In September 1994 , the Company sold substantially all of its brine disposal and well servicing assets located in Ohio. During 1996 the majority of the Company's brine disposal and well servicing activities are carried out in Oklahoma. In January 1997, the Company completed the sale of its brine disposal and well servicing activities in Oklahoma.

In total, field services provided revenues of $14.2 million in 1996, representing 16% of total revenues. Field service revenues for 1996 increased 41% over the prior year.

Gas Transportation and Marketing

The gas transportation and marketing revenues are comprised of fees for the transportation of production through gathering lines and income from marketing of oil and gas.

The Company's natural gas gathering and processing assets are primarily comprised of (i) its Sterling system obtained through the Cometra Acqusition, which consists of 265 miles of gas gathering pipelines and a gas processing plant in the Sterling area of the Permian Basin, and (ii) over 1,900 miles of gas gathering pipelines in Appalachia. The Sterling plant is a refrigerated turbo-expander cryogenic gas plant that was placed in service in early 1995. The plant, designed for approximately 25,000 Mcf/d, is currently operating at 87% of capacity. The Company estimates that the plant's capacity can be increased to 35,000 Mcf/d for approximately $4.0 million in additional capital expenditures.

The Appalachian gas gathering systems serve to transport a majority of the Company's Appalachian gas production as well as third party gas to major trunklines and directly to industrial end-users. This affords the Company considerable control and flexibility in marketing its Appalachian production. Third parties who transport their gas through the systems are charged a gathering fee ranging from $0.20 to $0.32 per Mcf.

In order to handle more efficiently the sale of its natural gas, the Company began to market its own gas production in 1993. Including activities of the Cometra properties, the Company is currently marketing 173 Mmcf/d for its own account as well as additional volumes for third party producers. The Company's gas production is sold primarily to utilities and directly to industrial users. The Company has managed the impact of potential price declines by developing a balanced portfolio of fixed price and market sensitive contracts and commodity hedging. Including production from the Cometra Properties, approximately 47% of average gas production at December 31, 1996 was sold subject to fixed price sales contracts. These fixed price contracts are at prices ranging from $2.15 to $3.70 per Mcf. The fixed price contracts with terms of less than one year, between one and five years and greater than five years constitute approximately 31%, 65% and 4%, respectively, of the volume sold under fixed price contracts.

From time to time, the Company enters into oil and natural gas price hedges to reduce its exposure to commodity price fluctuations. At December 31, 1996, approximately 12% on an Mcfe basis of the Company's monthly production for the period January 1997 to April 1997 was hedged under such arrangements. No production after this period was hedged. In the future, the Company may hedge a larger percentage of its production, however, it currently anticipates that such percentage would not exceed 50%. Although these hedging activities provide the Company some protection against falling prices, these activities also reduce the potential benefits to the Company of price increases above the levels of the hedges.

Interest and Other

The Company earns interest on its cash and investment accounts, as well as on various notes receivable. Other income in 1996 was comprised principally of gains on sales of marketable equity securities and gains on sales of non-strategic properties. The Company expects to continue to sell assets which have no strategic benefit. Interest and other income in 1996 amounted to $3.4 million, representing 4% of total revenues. Revenues from interest and other for 1996 increased 157% from the 1995 level.

COMPETITION

The Company encounters substantial competition in acquiring properties, marketing oil and gas, securing personnel and conducting its field services operations. Many competitors have financial and other resources which substantially exceed those of the Company. The competitors in acquisitions, development, exploration and production include the major oil companies in addition to numerous independents, individual proprietors and others. Therefore, competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects than the financial or personnel resources of the Company permit. The ability of the Company to replace and expand its reserve base in the future will be dependent upon its ability to select and acquire suitable producing properties and prospects for future drilling.

The Company's acquisitions have been partially financed through issuances of equity and debt securities and internally generated cash flow. The competition for capital to finance oil and gas acquisitions and drilling is intense. The ability of the Company to obtain such financing is uncertain and can be affected by numerous factors beyond its control. The inability of the Company to raise capital in the future could have an adverse effect on certain areas of its business.

GOVERNMENTAL REGULATION

The Company's operations are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are or have been subject to price controls, taxes and other laws and regulations relating to the oil and gas industry. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the Company's cost of doing business and affects its profitability. Although the Company believes it is in substantial compliance with all applicable laws and regulations, because such laws and regulations are frequently amended or reinterpreted, the Company is unable to predict the future cost or impact of complying with such laws and regulations.

ENVIRONMENTAL MATTERS

The Company's oil and natural gas exploration, development, production and pipeline gathering operations are subject to stringent federal, state and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments such as the Environmental Protection Agency ("EPA") issue regulations to implement and enforce such laws which are often difficult and costly to comply with and which carry substantial civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and pipeline gathering activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent pollution from former operations, such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from the Company's operations. In addition, these laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect the Company's operations and financial position, as well as the oil and gas industry in general. While management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and the Company has not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this will continue in the future.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Furthermore, although petroleum, including crude oil and natural gas, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and thus such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of oil and natural gas wastes are also pending in certain states, and these various initiatives could have a similar impact on the Company.

Stricter standards in environmental legislation may be imposed in the oil and gas industry in the future. For instance, legislation has been proposed in Congress from time to time that would reclassify certain oil and natural gas exploration and production wastes as "hazardous wastes" and make the reclassified wastes subject to more stringent handling, disposal and clean-up restrictions. If such legislation were to be enacted, it could have a significant impact on the operating costs of the Company, as well as the oil and gas industry in general. Compliance with environmental requirements generally could have a material adverse effect upon the capital expenditures, earnings or competitive position of the Company. Although the Company has not experienced any material adverse effect from compliance with environmental requirements, no assurance may be given that this will continue in the future.

The Federal Water Pollution Control Act ("FWPCA") imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into navigable waters. Permits must be obtained to discharge pollutants to state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and the federal (NPDES) permits prohibit or are expected to prohibit within the next year the discharge of produced water and sand, and some other substances related to the oil and gas industry, to coastal waters. Although the costs to comply with zero discharge mandated under federal or state law may be significant, the entire industry will experience similar costs and the Company believes that these costs will not have a material adverse impact on the Company's financial condition and results of operations. Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

The Resources Conservation and Recovery Act ("RCRA"), as amended, generally does not regulate most wastes generated by the exploration and production of oil and natural gas. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, are regulated as hazardous wastes. Although the costs of managing solid hazardous waste may be significant, the Company does not expect to experience more burdensome costs than similarly situated companies involved in oil and gas exploration and production.

In addition, the U.S. Oil Pollution Act ("OPA") requires owners and operators of facilities that could be the source of an oil spill into "waters of the United States" (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statutes.

EMPLOYEES

As of December 31, 1996, the Company had approximately 300 full time employees, of whom 190 were field personnel. None are covered by a collective bargaining agreement and management believes that its relationship with its employees is good.

ITEM 2. PROPERTIES

On December 31, 1996, including the Cometra Properties the Company held working interests in 7,280 gross (5,586 net) productive oil and gas wells and royalty interests in 310 additional wells. The properties contained, net to the Company's interest, estimated proved reserves of 498 Bcf of gas and 24 million barrels of oil or a total of 644 Bcfe. The Company also held interests in 902,700 gross (628,700 net) undeveloped acres at year end.

PROVED RESERVES

The following table sets forth estimated proved reserves for each year in the five year period ended December 31, 1996 and pro forma for the Cometra Acquisition.

	December 31,					Pro Forma
	1992	1993	1994	1995	1996	1996
Natural gas (Mmcf)						
Developed....................	13,171	38,373	97,251	174,958	207,601	311,350
Undeveloped..................	4,444	36,190	52,119	57,929	87,993	186,250
Total....................	17,615	74,563	149,370	232,887	295,594	497,600
Oil and NGL's (Mbbls)						
Developed....................	1,643	3,344	6,431	8,880	10,703	15,298
Undeveloped..................	337	1,195	2,018	1,983	3,972	9,107
Total....................	1,980	4,539	8,449	10,863	14,675	24,405
Total equivalents (Mmcfe)......	29,495	101,797	200,064	298,065	383,644	644,030

In connection with the evaluation of its reserves, the Company has engaged the following independent petroleum consultants: Netherland, Sewell & Associates, Inc. (Cometra Properties), Wright & Company, Inc. (Appalachia), H.J. Gruy and Associates, Inc. (Midcontinent and Gulf Coast), Huddleston & Co., Inc. (Midcontinent) and Clay, Holt & Klammer (Appalachia). These engineers have been employed primarily based on geographic expertise as well as their history in engineering certain of the acquired properties. At December 31, 1996, approximately 95% of the proved reserves set forth above were evaluated by independent petroleum consultants, while the remainder were evaluated by the Company's engineering staff. All estimates of oil and gas reserves are subject to significant uncertainty.

The following table sets forth as of December 31, 1996 the estimated future net cash flow from and the present value of the proved reserves. Future net cash flow represents future gross cash flow from the production and sale of proved reserves, net of production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. Such calculations, which are prepared in accordance with the Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities" are based on cost and price factors on December 31, 1996. Average product prices in effect at December 31, 1996 were $23.58 per barrel of oil and $3.54 per Mcf of gas and pro forma product prices in effect at December 31, 1996 were $23.23 per barrel of oil and $3.99 per Mcf of gas. There can be no assurance that the proved reserves will be developed within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of reserves have been filed with or included in reports to another federal authority or agency since December 31, 1996. The following is a table of estimated cash flows at December 31, 1996, including the Cometra properties.

	Developed	Undeveloped	Total
		(in thousands)	
Future net cash flow from estimated production of proved reserves			
1997	$ 133,587	$ (12,490)	$ 121,097
1998	235,187	17,183	252,370
1999	357,784	57,514	415,298
Remainder	412,146	589,857	1,002,003
Total	$ 1,138,704	$ 652,064	$ 1,790,768
Present value			
Pre-tax	$ 658,121	$ 315,541	$ 973,663
After-tax	N.A.	N.A.	$ 665,035

SIGNIFICANT PROPERTIES

At December 31, 1996, on a pro forma basis, 98% of the Company's reserves were located in the Midcontinent, the Gulf Coast and Appalachian regions. At December 31, 1996, the Company's properties included, on a pro forma basis, working interests in 7,280 gross (5,586 net) productive oil and gas wells and royalty interests in 310 additional wells. The Company also held interests in 243,100 gross (166,700 net) undeveloped acres on a pro forma basis at December 31, 1996. The following table sets forth summary information with respect to the Company's estimated proved oil and gas reserves on a pro forma basis at December 31, 1996.

	Present Value Amount (In thousands)	%	Oil & NGLs (Mbbls)	Natural Gas (Mmcfe)	Natural Gas Equiv. (Mmcf)
Midcontinent Region					
Permian Basin...........	$218,201	22%	12,468	54,833	129,642
Val Verde Basin.........	208,613	21	34	126,579	126,783
Anadarko Basin..........	125,143	13	1,964	71,065	82,851
San Juan Basin..........	43,845	5	3,082	16,836	35,326
Subtotal..............	595,802	61	17,548	269,313	374,602
Appalachian Region.........	201,215	21	1,189	181,325	188,456
Gulf Coast Region..........	160,353	16	4,179	46,403	71,477
Other......................	16,293	2	1,489	559	9,495
Total.................	$973,663	100%	24,405	497,600	644,030

MIDCONTINENT REGION

The Company's Midcontinent properties are situated in the Permian Basin of west Texas, the Val Verde Basin of west Texas, the Anadarko Basin of western Oklahoma and the Texas panhandle and the San Juan Basin of New Mexico. Reserves in these basins represent 61% of total Present Value. Midcontinent proved reserves total 375 Bcfe, of which approximately 57% are developed. On an Mcfe basis, 72% of the reserves are natural gas. Combined net daily production from these properties currently averages 3,300 barrels of oil and 52 Mmcf of natural gas. At December 31, 1996, the Midcontinent properties had an inventory of 674 proven development projects.

Permian Basin. The Permian Basin properties contain 130 Bcfe of proved reserves, or 22% of total Present Value. Net daily production currently averages 2,500 barrels of oil and 9 Mmcf of gas. Producing wells total 842 (617 net), of which the Company operates 88% on a Present Value basis. Major producing properties include the Sterling area and the Big Lake area. The Sterling area properties produce gas from Canyon/Cisco sub-marine sand deposits at 4,000 to 8,000 feet and oil from Silurian Fussleman carbonates. The Sterling area properties are complemented by a 25,000 Mcf/d gas plant, which processes gas from the Company's operated properties, as well as gas produced by third parties. The Big Lake area properties produce primarily oil from approximately 2,500 feet in various sequences of the San Andres/Grayburg formations. At December 31, 1996, the Permian Basin properties contained 85 proven recompletions and 129 development drilling locations.

Val Verde Basin. The Val Verde Basin properties contain 127 Bcfe of proved reserves, or 21% of total Present Value. From 205 gross wells (163 net), the Company currently produces 27 Mmcf/d of natural gas. The Company operates 89% of the wells on a Present Value basis. Production is from 15 different deltaic Canyon/Cisco sandstones with complex stratigraphic traps at depths ranging from 2,600 to 6,000 feet. On a Present Value basis, the Oakridge and Francis Hill Fields contribute 91% of the Val Verde Basin reserves. At December 31, 1996, the Company had an inventory of 76 proven recompletions and 134 development drilling locations.

Anadarko Basin. The Anadarko Basin properties contain 83 Bcfe of proved reserves, or 13% of total Present Value. The 431 gross wells (345 net), of which 65% are operated by the Company on a Present Value basis. Net daily production averages 440 barrels of oil and 14 Mmcf of natural gas. Over 250 operated wells in the Okeene Field account for 55% of the reserves on a Present Value basis. The Anadarko Basin wells produce from a variety of sands and carbonates in both structural and stratigraphic traps in the Hunton, Red Fork and Morrow formations at depths ranging from 6,000 to 12,000 feet. At December 31, 1996, 117 proven recompletions and 86 development drilling locations had been identified with respect to the Anadarko Basin properties.

San Juan Basin. The San Juan Basin properties contain 35 Bcfe of proved reserves, or 5% of total Present Value. The properties consist of 122 gross wells (116 net) located in the southeastern portion of the basin, all of which are Company operated. On an Mcfe basis, 52% of the reserves are oil and natural gas liquids. Current daily production averages 350 barrels of oil and natural gas liquids and 2 Mmcf of gas. Producing depths range from 2,000 to 8,000 feet in the tight blanket sands of the Gallup and Pictured Cliffs zones, as well as the Dakota formation. These properties have an inventory of 18 proven recompletions and 29 development drilling locations.

GULF COAST REGION

The Gulf Coast region consists of onshore properties located in the East Texas Basin and in South Texas, as well as offshore properties located in the Gulf of Mexico. Reserves in these areas represent 16% of the Company's total Present Value. Gulf Coast properties contain 71 Bcfe of proved reserves, of which approximately 63% are developed. On an Mcfe basis, 65% of the reserves are natural gas. Current net daily production from these properties averages 1,800 barrels of oil and 21 Mmcf of natural gas. At December 31, 1996, the Gulf Coast properties were estimated to contain 126 proven development projects.

South Texas/Gulf of Mexico. The South Texas/Gulf of Mexico properties contain 54 Bcfe of proved reserves, or 13% of total Present Value. On an Mcfe basis, gas makes up 79% of the reserves. Current net daily production from the South Texas/Gulf of Mexico properties totals 1,200 barrels of oil and 21 Mmcf of gas. Onshore South Texas, these fields range in location from Brooks County in deep South Texas to Galveston County, near Houston. Significant fields include Hagist Ranch, Alta Mesa, Riverside, Keeran/Welder and Moses Bayou. These fields produce from the Wilcox, Frio, Yegua, Vicksburg and Miocene at depths ranging from 1,000 to 10,000 feet. In total, the onshore fields include 179 gross wells (153 net), of which 92% are Company operated. The offshore properties in the Gulf of Mexico include seven platforms offshore Texas and Louisiana in water depths ranging from 50 to 220 feet. All 15 gross wells (4 net) are operated by experienced third parties. The Company's working interest in these wells ranges from 11% to 33%. The offshore properties produce from the Miocene and Pleistocene age formations, at depths ranging from 8,000 to 14,000 feet. With multiple producing horizons, untested formations and complex faulting, the South Texas/Gulf of Mexico properties contain substantial development and exploration potential, including the continued use of 3-D seismic technology. At December 31, 1996, these properties are estimated to contain 15 proven recompletions and 24 development drilling locations.

East Texas Basin. The East Texas properties contain 18 Bcfe of proved reserves accounting for 3% of total Present Value. On an Mcfe basis, 79% of the reserves are oil. Gross wells total 126 (110 net), of which 74% are Company operated. Current net daily production averages 620 barrels of oil and 150 Mcf of gas. Production ranges from the shallow Carrizo section of the Wilcox formation at a depth of approximately 1,600 feet to the tight Cotton Valley Taylor blanket sands at approximately 12,000 feet. Approximately 79% of the Present Value of the East Texas properties is ascribed to 64 operated wells in the Laura LaVelle Field. At December 31, 1996, 64 proven recompletions and 23 development drilling locations had been identified in the East Texas properties.

APPALACHIAN REGION

The Appalachian properties contain 188 Bcfe of proved reserves, or 21% of total Present Value. The reserves are attributable to 5,326 gross wells (4,417 net wells) located in Pennsylvania, Ohio, West Virginia and New York. The Company operates 94% of these wells. The reserves, which on an Mcfe basis are 96% natural gas, produce principally from the Medina, Clinton and Rose Run formations at depths ranging from 2,500 to 7,000 feet. Net daily production currently totals 400 barrels of oil and 32 Mmcf of gas. After initial flush production, these properties are characterized by gradual decline rates. Gas production is transported through 1,900 miles of Company owned gas gathering systems and is sold primarily to utilities and industrial end-users.

PRODUCTION

The following table sets forth production information for the preceding five years (in thousands, except average sales price and operating cost data).

	Year Ended December 31,					
	1992	1993	1994	1995	1996	Pro Forma 1996
Production						
Oil and NGL's (Bbl) ...	199	318	640	913	1,068	1,890
Gas (Mcf)	1,796	2,590	6,996	12,471	21,231	38,157
Mcfe (a)	2,990	4,498	10,836	17,949	27,641	49,497
Revenues						
Oil	$ 3,660	$ 5,118	$ 9,743	$ 15,133	$ 20,425	$ 35,506
Gas	4,043	6,014	14,718	22,284	47,629	95,002
Total	$ 7,703	$ 11,132	$ 24,461	$ 37,417	$ 68,054	$130,508
Direct operating expenses	3,019	4,438	10,019	14,930	24,456	39,394
Gross margin	$ 4,684	$ 6,694	$ 14,442	$ 22,487	$ 43,598	$ 91,114
Average sales price						
Oil (Bbl)	$ 18.40	$ 16.07	$ 15.23	$ 16.57	$ 19.12	$ 18.79
Gas (Mcf)	$ 2.25	$ 2.32	$ 2.10	$ 1.79	$ 2.24	$ 2.49
Mcfe (a)	$ 2.58	$ 2.47	$ 2.26	$ 2.08	$ 2.46	$ 2.64
Average operating expense per Mcfe	$ 0.99	$ 0.98	$ 0.93	$ 0.83	$ 0.88	$ 0.80

(a) Oil is converted to Mcfe at a rate of 6 Mcf per barrel, based upon relative energy content.

PRODUCING WELLS

The following table sets forth certain information relating to productive wells at December 31, 1996, including the Cometra Properties. The Company owns royalty interests in an additional 310 wells. Wells are classified as oil or gas according to their predominant production stream.

	Gross Wells	Net Wells	Average Working Interest
Crude oil..................	1,510	816	54%
Natural gas................	5,770	4,770	83%
Total.................	7,280	5,586	77%

ACREAGE

The following table sets forth the developed and undeveloped acreage held at December 31, 1996, including the Cometra Properties.

	Gross	Net	Average Working Interest
Developed..................	659,619	461,999	70%
Undeveloped................	243,088	166,725	69%
Total.................	902,707	628,724	70%

DRILLING RESULTS

The following table summarizes drilling activities for the three years ended December 31, 1996. The drilling results below do not reflect the Cometra Acquisition (or any other acquisitions).

	Year Ended December 31,					
	1994		1995		1996	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	3.0	0.1	5.0	0.4	7.0	3.4
Dry	6.0	1.5	2.0	0.2	4.0	1.1
Development wells:						
Productive	61.0	56.3	53.0	38.8	49.0	45.2
Dry	1.0	0.3	2.0	0.2	3.0	2.2
Total	71.0	58.2	62.0	39.6	63.0	51.9

GAS GATHERING AND PROCESSING

The Company's natural gas gathering and processing assets are primarily comprised of (i) its Sterling system, which consists of 265 miles of gas gathering pipelines and a gas processing plant in the Sterling area of the Permian Basin, and (ii) over 1,900 miles of gas gathering pipelines in Appalachia. The Sterling plant is a refrigerated turbo-expander cryogenic gas plant that was placed in service in early 1995. The plant, designed for approximately 25,000 Mcf/d, is currently operating at 87% of capacity. The Company estimates that the plant's capacity can be increased to 35,000 Mcf/d for approximately $4.0 million in additional capital expenditures.

The Appalachian gas gathering systems serve to transport a majority of the Company's Appalachian gas production as well as third party gas to major trunklines and directly to industrial end-users. This affords the Company considerable control and flexibility in marketing its Appalachian production. Third parties who transport their gas through the systems are charged a gathering fee ranging from $0.20 to $0.32 per Mcf.

OIL AND GAS MARKETING

In order to handle more efficiently the sale of its natural gas, the Company began to market its own gas production in 1993. On a pro forma basis, the Company is currently marketing 173 Mmcf/d for its own account as well as additional volumes for third party producers. The Company's gas production is sold primarily to utilities and directly to industrial users.

The Company has managed the impact of potential price declines by developing a balanced portfolio of fixed price and market sensitive contracts and commodity hedging. On a pro forma basis, approximately 47% of average gas production at December 31, 1996 was sold subject to fixed price sales contracts. These fixed price contracts are at prices ranging from $2.15 to $3.70 per Mcf. The fixed price contracts with terms of less than one year, between one and five years and greater than five years constitute approximately 31%, 65% and 4%, respectively, of the volume sold under fixed price contracts.

From time to time, the Company enters into oil and natural gas price hedges to reduce its exposure to commodity price fluctuations. At December 31, 1996, approximately 12% on an Mcfe basis of the Company's monthly production for the period January 1997 to April 1997 was hedged under such arrangements. No production after this period was hedged. In the future, the Company may hedge a larger percentage of its production.

Approximately 30% of the Company's pro forma December 1996 gas production on an Mcfe basis was attributable to Appalachia. Gas production in Appalachia has historically received a higher price, due to its proximity to the northeastern gas markets.

The Company's oil production is sold at the well site at posted field prices tied to the spot oil markets. Oil purchasers are selected on the basis of price and service.

As part of the Cometra Acquisition, the Company acquired a gas contract, which expires June 30, 2000, with a major Texas gas utility company representing 17% of the Company's pro forma December 1996 production on an Mcfe basis. The price paid pursuant to the contract was $3.70 per Mcf at December 31, 1996 (65% higher than average 1996 natural gas prices received by the Company) and escalates at $0.05 per Mcf per annum. No other purchaser of the Company's oil or gas during 1996 exceeded 10% of the Company's total revenues.

REAL PROPERTY

The Company owns a 24,000 square foot facility located on approximately seven acres near Hartville, Ohio. The facility houses certain operating and administrative personnel. The Company leases approximately 33,000 square feet in Fort Worth and Oklahoma City under standard office lease arrangements that expire at various times through March 2004. All facilities are adequate to meet the Company's existing needs and can be expanded with minimal expense.

The Company owns various rolling stock and other equipment which is used in its field operations. Such equipment is believed to be in good repair and, while such equipment is important to its operations, it can be readily replaced as necessary.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various legal actions and claims arising in the ordinary course of business. In the opinion of management, such litigation and claims will be resolved without a material adverse effect on the Company's financial position.

The Company recently received notice from two parties, each of whom claims that it is entitled to fees from the Company based upon a Yemen oil concession that they claim Red Eagle Resources Corporation received in August 1992, which was prior to the acquisition of Red Eagle by the Company. Based upon the Company's examination of the available documentation relevant to such claims, the Company believes that the claims are without merit because the claimed oil concession was never obtained in Yemen. The Company has requested further documentation from the two parties with respect to their claims but no such documentation has yet been provided. The claims are for approximately $4.0 million in the aggregate (including the value of approximately 70,000 shares of Common Stock that would be required to be issued if the oil concession had been obtained). To date, no proceedings have been commenced with respect to either of these claims.

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

None.

PART II

ITEM 5. MARKET FOR THE COMMON STOCK AND RELATED MATTERS

The Company's Common Stock is listed on NYSE under the symbol "LOM". Prior to listing on the NYSE, the Common Stock was listed on the Nasdaq National Market under the symbol "LOMK". During 1996, trading volume averaged 117,600 shares per day. The stock prices below are based on the last trade price. On March 17, 1997, the closing price of the Common Stock was $18.25. To date in 1997, trading volume has averaged 217,200 shares per day. The following table sets forth the high and low sales prices as reported on the NYSE Composite Transaction Tape or the Nasdaq National Market, as applicable on a quarterly basis for the periods indicated.

	High	Low	Common Stock Dividends	Average Daily Volume (shares)
1996				
Fourth Quarter	$17.375	$13.125	$ .02	102,140
Third Quarter	14.875	12.750	.02	97,380
Second Quarter	15.500	11.625	.01	92,400
First Quarter	12.125	9.560	.01	133,800
1995				
Fourth Quarter	$7.500	$5.500	$ .01	92,000
Third Quarter	9.250	7.250	-	80,700
Second Quarter	8.188	7.250	-	111,500
First Quarter	7.375	5.500	-	57,800

DIVIDENDS

Dividends on the Common Stock were initiated in December 1995 and have been paid each successive quarter. The $2.03 Convertible Preferred Stock receives cumulative quarterly dividends at the annual rate of $2.03 per share. If there is any arrearage in dividends on the $2.03 Convertible Preferred Stock, the Company may not pay dividends on the Common Stock. The Company has never been in arrears in the payment of dividends on the $2.03 Convertible Preferred Stock.

The payment of dividends is subject to declaration by the Board of Directors and may depend on earnings, capital expenditures and market factors existing from time to time. The Amended Credit Facility and the Indenture for the 6% Convertible Subordinated Debenture Due 2007 and 8.75% Senior Subordinated Notes due 2007 contain restrictions on the Company's ability to pay dividends on capital stock. Under the most restrictive of these provisions, the Company could have paid $5,000,000 of dividends as of December 31, 1996.

HOLDERS OF RECORD

At March 17, 1997, the number of holders of record of the Common Stock, and $2.03 Convertible Preferred Stock were approximately 4,300 and 2, respectively.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected financial information covering the preceding five years.

	As of or for the Year Ended December 31,					Pro Forma
	1992	1993	1994	1995	1996	1996
	(In thousands, except per share data)					
OPERATIONS						
Revenues	$ 13,895	$ 19,075	$ 34,794	$ 52,115	$ 91,238	$172,443
Net income	686	1,391	2,619	4,390	12,615	18,644
Earnings per common share	.08	.18	.25	.31	.69	.80
BALANCE SHEET						
Working capital	$ 167	$ 1,350	$ 1,002	$ 4,563	$ 12,896	$ 12,896
Oil and gas properties, net	18,599	55,310	112,964	176,702	229,417	554,417
Total assets	28,328	76,333	141,768	214,788	282,547	671,597
Long-term debt (a)	13,127	31,108	62,592	83,088	116,806	411,756
Stockholders' equity	9,504	32,263	43,248	99,367	117,529	211,629

(a) Long-term debt includes current portion

The following table sets forth summary unaudited financial information on a quarterly basis for the past two years (in thousands, except per share data).

	1995			
	Mar. 31	June 30	Sept. 30	Dec. 31
Revenues	$ 10,903	$ 11,588	$ 12,136	$ 17,488
Net income	795	1,026	897	1,672
Earnings per common share	.07	.08	.07	.10
Total assets	151,801	157,222	203,305	214,788
Long-term debt (a)	66,835	71,635	113,238	83,088
Stockholders' equity	57,701	58,884	60,554	99,367

	1996			
	Mar. 31	June 30	Sept. 30	Dec. 31
Revenues	$20,513	$22,774	$22,312	$25,639
Net income	2,603	2,780	2,719	4,513
Earnings per common share	0.14	0.15	0.14	0.26
Total assets	232,207	274,041	284,152	282,547
Long-term debt (a)	95,116	119,380	121,905	116,806
Stockholders' equity	101,146	110,762	112,866	117,529

(a) Long-term debt includes current portion.

The total of the earnings per share for each quarter does not equal the earnings per share for the full year, either because the calculations are based on the weighted average shares outstanding during each of the individual periods, or due to rounding.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FACTORS EFFECTING FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY AND CAPITAL RESOURCES

General

Working capital at December 31, 1996 was $12.9 million, representing an $8.3 million increase over the corresponding amount at December 31, 1995. At December 31, 1996, the Company had $8.6 million in cash and total assets of $282.5 million. During 1996, long-term debt rose from $83.0 million to $116.8 million.

At December 31, 1996, capitalization totaled approximately $234 million, of which approximately 50% was represented by stockholders' equity and 50% by long-term debt. Approximately $61.4 million of the long-term debt at that date was comprised of borrowings under the Credit Agreement, $55 million being comprised of 6% Convertible Subordinated Debentures and the remaining $500,000 comprised of other indebtedness. The Credit Agreement currently provides for quarterly payments of interest with principal due in February 2002.

In December 1996, the Company sold $55 million of 6% Convertible Subordinated Debentures in a private placement. Net proceeds to the Company of approximately $53 million were used, together with internally generated funds, to reduce the amount outstanding under the Credit Agreement to $61.4 million at December 31, 1996. The 6% Convertible Subordinated Debentures are redeemable by the Company after February 1, 2000 and are convertible at the option of the holder into Common Stock at any time prior to maturity or redemption at a conversion price of $19.25 per share, subject to adjustment in certain circumstances.

Cash Flow

The Company has three principal operating sources of cash: (i) sales of oil and gas; (ii) revenues from field services and (iii) revenues from gas transportation and marketing. The Company's cash flow is highly dependent upon oil and gas prices. Decreases in the market price of oil or gas could result in reductions of both cash flow and the borrowing base under the Credit Agreement which would result in decreased funds available, including funds intended for planned capital expenditures.

The Company's net cash provided by operations for the years ended December 31, 1994, 1995 and 1996 was $11.2 million, $16.6 million and $38.4 million, respectively. The consistent increases in the Company's cash flow from operations can be attributed to its growth primarily through acquisitions and development.

The Company's net cash used in investing for the years ended December 31, 1994, 1995 and 1996 was $29.5 million, $76.1 million and $69.7 million, respectively. Investing activities for these periods are comprised primarily of additions to oil and gas properties through acquisitions and development and, to a lesser extent, exploitation and additions of field service assets. These uses of cash have historically been partially offset through the Company's policy of divesting those properties that it deems to be marginal or outside the Company's core areas of operations. The Company's acquisition and development activities have been financed through a combination of operating cash flow, bank borrowings and capital raised through equity and debt offerings.

The Company's net cash provided by financing for the years ended December 31, 1994, 1995 and 1996 was $21.2 million, $57.7 million and $36.8 million, respectively. Sources of financing used by the Company have been primarily borrowings under its Credit Agreement and capital raised through equity and debt offerings.

Capital Requirements

In 1996, $12.5 million and $2.0 million of expenses were incurred for development activities and exploration activities, respectively. Although these expenditures are principally discretionary, the Company is currently projecting that it will spend approximately $160 million on development, exploitation and exploration activities, which includes approximately $45 million on exploitation and exploration expenditures, for the three years ending 1999. For the next three years, development and exploration expenditures are currently expected to consume roughly 50% of internally generated cash flows. The remaining funds will be available for acquisitions and other capital expenditures. See "Business--Development Activities" and "--Exploration Activities."

Credit Agreement

In connection with the financing of the Cometra Acquisition, the Company and its subsidiaries expanded the existing bank credit facility. The Credit Agreement permits the Company to obtain revolving credit loans and to issue letters of credit for the account of the Company from time to time in an aggregate amount not to exceed $400 million (of which not more than $150 million may be represented by letters of credit). The Borrowing Base, which was initially $400 million, was reduced to $300 million upon the consummation of the Offerings. The Borrowing Base is subject to semi-annual determination and certain other redeterminations based upon a variety of factors, including the discounted present value of estimated future net cash flow from oil and gas production. The Company is required to make a mandatory prepayment of all amounts outstanding under the Credit Agreement in excess of $300 million. At the Company's option, loans may be prepaid, and revolving credit commitments may be reduced, in whole or in part at any time in certain minimum amounts. Security obligations in place with the Credit Agreement were released upon the consummation of the Offerings on March 14, 1997.

At the Company's option, the applicable interest rate per annum is either the Eurodollar loan rate plus a margin ranging from 0.625% to 1.125% or the Alternate Base Rate (as defined) plus a margin ranging from 0% to 0.25%. The Alternate Base Rate is the higher of (a) the administrative agent bank's prime rate and (b) the federal funds effective rate plus 0.5%.

On March 17, 1997, approximately $204 million was outstanding (including $134 million of then outstanding letters of credit to secure the promissory note issued to Cometra as part of the purchase price in the Cometra Acquisition) under the Credit Agreement.

Common Stock and Notes Offering

On March 14, 1997, the Company completed a 4,060,000 million share Common stock offering (the "Common Offering") and a $125 million aggregate principal amount of its 8.75% Senior Subordinated Notes due 2007 (the "Notes Offering")(collectively the "Offerings"). The Notes are unconditionally guaranteed on an unsecured, senior subordinated basis, by each of the Company's Restricted Subsidiaries (as defined in the Indenture for the Notes), provided that such guarantees will terminate under certain circumstances. The Indenture for the Notes contains certain covenants, including, but not limited to, covenants with respect to the following matters: (i) limitation on restricted payments; (ii) limitation on the incurrence of indebtedness and issuance of Disqualified Stock (as defined in the Indenture for the Notes); (iii) limitation on liens; (iv) limitation on disposition of proceeds of asset sales; (v) limitation on transactions with affiliates; (vi) limitation on dividends and other payment restrictions affecting restricted subsidiaries; (vii) restrictions on mergers, consolidations and transfers of assets; and (viii) limitation on "layering" indebtedness.

Hedging Activities

Periodically, the Company enters into futures, option and swap contracts to reduce the effects of fluctuations in crude oil and natural gas prices. At December 31, 1996, the Company had open contracts for oil and gas price swaps of 300,000 barrels of oil at average prices ranging from $22.10 to $22.76 per barrel of oil and 155,000 MmBtu of gas at $2.04 per MmBtu. While these transactions have no carrying value, the Company's mark-to-market exposure under these contracts at December 31, 1996 was a net loss of $1.1 million. These contracts expire monthly through April 1997. The gains or losses on the Company's hedging transactions is determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. The resulting transaction gains and losses are determined monthly and are included in the period the hedged production or inventory is sold. Net gains or losses relating to these derivatives for the years ended December 31, 1994, 1995 and 1996 approximated $0, $217,000 and $(724,000), respectively.

INFLATION AND CHANGES IN PRICES

The Company's revenues and the value of its oil and gas properties have been and will be affected by changes in oil and gas prices. The Company's ability to maintain current borrowing capacity and to obtain additional capital on attractive terms is also substantially dependent on oil and gas prices. Oil and gas prices are subject to significant seasonal and other fluctuations that are beyond the Company's ability to control or predict. During 1996, the Company received an average of $19.12 per barrel of oil and $2.24 per Mcf of gas. Although certain of the Company's costs and expenses are affected by the level of inflation, inflation did not have a significant effect in 1996. Should conditions in the industry improve, inflationary cost pressures may resume.

RESULTS OF OPERATIONS

Comparison of 1996 to 1995

The Company reported net income for the year ended December 31, 1996 of $12.6 million, a 187% increase over 1995. The increase is the result of (i) higher production volumes, over 60% of which is attributable to acquisitions and the remainder is attributable to development activities; (ii) increased prices received from the sale of oil and gas products and (iii) gains from asset sales. During the year, oil and gas production volumes increased 54% to 27.6 Bcfe, an average of 76 Mmcfe/d. The increased revenues recognized from production volumes were aided by an 18% increase in the average price received per Mcfe of production to $2.46. The average oil price increased 15% to $19.12 per barrel while average gas prices increased 25% to $2.24 per Mcf. As a result of the Company's larger base of producing properties and production, oil and gas production expenses increased 64% to $24.5 million in 1996 versus $14.9 million in 1995. The average operating cost per Mcfe produced increased 6% from $0.83 in 1995 to $0.88 in 1996 due to unsuccessful recompletion costs and increases in personnel costs.

Gas transportation and marketing revenues increased 70% to $5.6 million versus $3.3 million in 1995 principally due to production growth. Gas transportation and marketing expenses increased 97% to $1.7 million versus $0.8 million in 1995. The increase in expenses was due to production growth, as well as the increase in gas transportation and marketing expense and higher administrative costs associated with the growth in gas marketing.

Field services revenues increased 41% in 1996 to $14.2 million. The higher revenues were due primarily to a larger base of operated properties. Field services expenses increased 61% in 1996 to $10.4 million versus $6.5 million. The increase is attributed to the cost of operating a larger base of properties and lower overall margins on Oklahoma well servicing. In December 1996, the Company sold its brine disposal and well servicing activities in Oklahoma for $2.7 million and recorded a gain of approximately $1.2 million, which is included in interest and other income.

Exploration expense increased 185% to $1.5 million due to the Company's increased involvement in seismic and exploratory drilling. The Company participated in 11 exploratory wells in 1996 versus 7 exploratory wells in 1995.

General and administrative expenses increased 45% from $2.7 million in 1995 to $3.9 million in 1996. As a percentage of revenues, general and administrative expenses were 4% in 1996 as compared to 5% in 1995. This decreasing trend reflects the spreading of administrative costs over a growing asset base.

Interest and other income rose 157% to $3.4 million primarily due to $1.4 million on gains from sale of marketable securities (which were not related to hedging activities), and $1.2 million from the gain on the sale of the Oklahoma well servicing assets. Interest expense increased 34% to $7.5 million as compared to $5.6 million in 1995. This was primarily as a result of the higher average outstanding debt balance during the year due to the financing of capital expenditures. The average outstanding balances on the Credit Agreement were $73.3 million and $107.2 million for 1995 and 1996, respectively. The weighted average interest rate on these borrowings were 7.3% and 6.7% for the years ended December 31, 1995 and 1996, respectively.

Depletion, depreciation and amortization increased 50% compared to 1995 as a result of increased production volumes during the year. The Company-wide depletion rate was $0.73 per Mcfe in 1995 and 1996.

Comparison of 1995 to 1994

The Company reported net income for the year ended December 31, 1995 of $4.4 million, a 68% increase over 1994. This increase is the result of higher production volumes attributable to acquisition and development activities.

During the year, oil and gas production volumes increased 66% to 17.9 Bcfe, an average of 49.2 Mmcfe/d. The increased revenues recognized from production volumes were partially offset by an 8% decrease in the average price received per Mcfe of production to $2.08. The average oil price increased 9% to $16.57 per barrel while average gas prices dropped 15% to $1.79 per Mcf. As a result of the Company's larger base of producing properties and production, oil and gas production expenses increased 49% to $14.9 million in 1995 versus $10.0 million in 1994. However, the average operating cost per Mcfe produced decreased 11% from $0.93 in 1994 to $0.83 in 1995.

Gas transportation and marketing revenues increased 50% to $3.3 million versus $2.2 million in 1994. Coupled with this increase in gas transportation and marketing revenues was a 73% increase in associated expenses for the year. These increases were due primarily to the acquisition of several pipeline systems, as well as the expansion of the gas marketing efforts.

Field services revenues increased 32% in 1995 to $10.1 million, despite the September 1994 sale of virtually all well servicing and brine disposal assets in Ohio. The decrease in activities due to this sale was more than offset by an increase in well servicing and brine disposal activities in Oklahoma and well operations on acquired properties. Field services expenses increased 12% in 1995 to $6.5 million versus $5.8 million. The increase is attributed to the Oklahoma well servicing and the cost of operating a larger base of properties. The increase in well operating costs was offset to a great extent by the disposal in September 1994 of the Company's lower margin well servicing and brine hauling and disposal businesses.

Exploration expense increased 43% to $0.5 million due to the Company's increased involvement in exploration projects. These costs include delay rentals, seismic and exploratory drilling activities.

General and administrative expenses increased 10% from $2.5 million in 1994 to $2.7 million in 1995. As a percentage of revenues, general and administrative expenses were 5% in 1995 as compared to 7% in 1994. This improvement reflects the spreading of administrative costs over a growing asset base.

Interest and other income rose 180% primarily due to higher sales of non-strategic properties. Interest expense increased 99% to $5.6 million as compared to $2.8 million in 1994. This was primarily as a result of the higher average outstanding debt balance during the year due to the financing of capital expenditures. The average outstanding balances on the Credit Agreement were $42.0 million and $73.3 million for 1994 and 1995, respectively. The weighted average interest rate on these borrowings was 6.3% and 7.3% for the years ended December 31, 1994 and 1995, respectively.

Depletion, depreciation and amortization increased 47% compared to 1994 as a result of increased production volumes during the year. The increased depletion of oil and gas properties was partially offset by the reduction of depreciation of field services assets due to the 1994 sale of field service assets. The Company-wide depletion rate for 1995 was $0.73 per Mcfe versus $0.74 per Mcfe in 1994 due to the addition of properties at lower than historical Mcfe costs.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the Index to Financial Statements on page 29 for a listing of the Company's financial statements and notes thereto and for supplementary schedules. Schedules I, III, IV, V, VI, VII, VIII, IX, X, XI, XII and XIII have been omitted as not required or not applicable or because the information required to be presented is included in the financial statements and related notes.

MANAGEMENT RESPONSIBILITY FOR FINANCIAL STATEMENTS

The financial statements have been prepared by management in conformity with generally accepted accounting principles. Management is responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

The Company maintains accounting and other controls which management believes provide reasonable assurance that financial records are reliable, assets are safeguarded, and that transactions are properly recorded. However, limitations exist in any system of internal control based upon the recognition that the cost of the system should not exceed benefits derived.

The Company's independent auditors, Arthur Andersen LLP, are engaged to audit the financial statements and to express an opinion thereon. Their audit is conducted in accordance with generally accepted auditing standards to enable them to report whether the financial statements present fairly, in all material respects, the financial position and results of operations in accordance with generally accepted accounting principles.

ITEM 9. CHANGE IN ACCOUNTANTS AND DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY

The current executive officers and directors of the Company are listed below, together with a description of their experience and certain other information. Each of the directors was elected for a one-year term at the Company's 1997 annual meeting of stockholders. Executive officers are appointed by the Board of Directors.

NAME	AGE	HELD OFFICE SINCE	POSITION WITH COMPANY
Thomas J. Edelman	46	1988	Chairman and Chairman of the Board
John H. Pinkerton	42	1988	President, Chief Executive Officer and Director
Robert E. Aikman	65	1990	Director
Anthony V. Dub	47	1995	Director
Allen Finkelson	50	1994	Director
Ben A. Guill	46	1995	Director
C. Rand Michaels	59	1976	Vice Chairman and Director
Jeffery A. Bynum	42	1985	Vice President-Land
Steven L. Grose	48	1980	Vice President-Appalachia Region
Chad L. Stephens	41	1990	Vice President-Midcontinent Region
Thomas W. Stoelk	41	1994	Vice President-Finance
Danny M. Sowell	46	1996	Vice President-Gas Management
John R. Frank	41	1990	Controller
Geoffrey T. Doke	30	1996	Treasurer

Thomas J. Edelman holds the office of Chairman and is Chairman of the Board of Directors. Mr. Edelman joined the Company in 1988 and served as its Chief Executive Officer until 1992. From 1981 to February 1997, Mr. Edelman served as a director and President of Snyder Oil Corporation ("SOCO"), an independent, publicly traded oil and gas company. Mr. Edelman currently serves as an employee of SOCO. In 1996, Mr. Edelman was appointed Chairman, President and Chief Executive Officer of Patina Oil & Gas Corporation, a publicly traded affiliate of SOCO. Prior to 1981, Mr. Edelman was a Vice President of The First Boston Corporation. From 1975 through 1980, Mr. Edelman was with Lehman Brothers Kuhn Loeb Incorporated. Mr. Edelman received his Bachelor of Arts Degree from Princeton University and his Masters Degree in Finance from Harvard University's Graduate School of Business Administration. Mr. Edelman is also a director of Petroleum Heat & Power Co., Inc., a Connecticut-based fuel oil distributor, Star Gas Corporation, a private company, which is the general partner of Star Gas Partners, L.P., a publicly-traded master limited partnership, which distributes propane gas.

John H. Pinkerton, President, Chief Executive Officer and a Director, joined the Company in 1988. He was appointed President in 1990 and Chief Executive Officer in 1992. Previously, Mr. Pinkerton was a Senior Vice President-Acquisitions of SOCO. Prior to joining SOCO in 1980, Mr. Pinkerton was with Arthur Andersen & Co. Mr. Pinkerton received his Bachelor of Arts Degree in Business Administration from Texas Christian University and his Master of Arts Degree in Business Administration from the University of Texas. Mr. Pinkerton is also director of North Coast Energy, Inc. ("North Coast"), an exploration and production company in which Lomak acquired an approximately 50% interest in 1996.

Robert E. Aikman, a Director, joined the Company in 1990. Mr. Aikman has more than 40 years experience in petroleum and natural gas exploration and production throughout the United States and Canada. From 1984 to 1994 he was Chairman of the Board of Energy Resources Corporation. From 1979 through 1984, he was the President and principal shareholder of Aikman Petroleum, Inc. From 1971 to 1977, he was President of Dorchester Exploration Inc. and from 1971 to 1980, he was a Director and a member of the Executive Committee of Dorchester Gas Corporation. Mr. Aikman is also Chairman of Provident Trade Company, President of EROG, Inc., and President of The Hawthorne Company, an entity which organizes joint ventures and provides advisory services for the acquisition of oil and gas properties, including the financial restructuring, reorganization and sale of companies. He was President of Enertec Corporation which was reorganized under Chapter 11 of the Bankruptcy Code in December 1994. In addition, Mr. Aikman is a director of the Panhandle Producers and Royalty Owners Association and a member of the Independent Petroleum Association of America, Texas Independent Producers and Royalty Owners Association and American Association of Petroleum Landmen. Mr. Aikman graduated from the University of Oklahoma in 1952.

Anthony V. Dub was elected to serve as a Director of the Company in 1995. Mr. Dub is Managing Director-Senior Advisor of Credit Suisse First Boston, an international investment banking firm with headquarters in New York City. Mr. Dub joined Credit Suisse First Boston in 1971 and was named a Managing Director in 1981. Mr. Dub received his Bachelor of Arts Degree from Princeton University in 1971.

Allen Finkelson was appointed a Director in 1994. Mr. Finkelson has been a partner at Cravath, Swaine & Moore since 1977, with the exception of the period from September 1983 through August 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson was first employed by Cravath, Swaine & Moore as an associate in 1971. Mr. Finkelson received his Bachelor of Arts Degree from St. Lawrence University and his Doctor of Laws Degree from Columbia University School of Law.

Ben A. Guill was elected to serve as a Director of the Company in 1995. Mr. Guill is a Partner and Managing Director of Simmons & Company International, an investment banking firm located in Houston, Texas focused exclusively on the oil service and equipment industry. Mr. Guill has been with Simmons & Company since 1980. Prior to joining Simmons & Company, Mr. Guill was with Blyth Eastman Dillon & Company from 1978 to 1980. Mr. Guill received his Bachelor of Arts Degree from Princeton University and his Masters Degree in Finance from the Wharton Graduate School of Business at the University of Pennsylvania.

C. Rand Michaels, who holds the office of Vice Chairman and is a Director, served as President and Chief Executive Officer of the Company from 1976 through 1988 and Chairman of the Board from 1984 through 1988, when he became Vice Chairman. Mr. Michaels received his Bachelor of Science Degree from Auburn University and his Master of Business Administration Degree from the University of Denver. Mr. Michaels is also a director of American Business Computers Corporation of Akron, Ohio, a public company serving the beverage dispensing and fast food industries, and North Coast.

Jeffery A. Bynum, Vice President-Land and Secretary, joined the Company in 1985. Previously, Mr. Bynum was employed by Crystal Oil Company and Kinnebrew Energy Group of Shreveport, Louisiana. Mr. Bynum holds a Professional Certification with American Association of Petroleum Landmen and attended Louisiana State University in Baton Rouge, Louisiana and Centenary College in Shreveport, Louisiana.

Steven L. Grose, Vice President-Appalachia Region, joined the Company in 1980. Previously, Mr. Grose was employed by Halliburton Services, Inc. as a Field Engineer from 1971 until 1974. In 1974, he was promoted to District Engineer and in 1978, was named Assistant District Superintendent based in Pennsylvania. Mr. Grose is a member of the Society of Petroleum Engineers and a trustee of The Ohio Oil and Gas Association. Mr. Grose received his Bachelor of Science Degree in Petroleum Engineering from Marietta College. Mr. Grose is also a director of North Coast.

Chad L. Stephens, Vice President-Midcontinent Region, joined the Company in 1990. Previously, Mr. Stephens was a landman with Duer Wagner & Co., an independent oil and gas producer, since 1988. Prior thereto, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was a landman for Cities Service Company and HNG Oil Company. Mr. Stephens received his Bachelor of Arts Degree in Finance and Land Management from the University of Texas.

Thomas W. Stoelk, Vice President-Finance and Chief Financial Officer, joined the Company in 1994. Mr. Stoelk is a Certified Public Accountant and was a Senior Manager with Ernst & Young LLP. Prior to rejoining Ernst & Young LLP in 1986 he was with Partners Petroleum, Inc. Mr. Stoelk received his Bachelor of Science Degree in Industrial Administration from Iowa State University.

Danny M. Sowell, Vice President-Gas Management, joined the Company in 1996. Previously, Mr. Sowell was Chief Executive Officer and President of Jay Gas Marketing, which Lomak acquired May 1, 1996. Prior to founding Jay Gas, Mr. Sowell was Director of Marketing for a subsidiary of Oklahoma Gas & Electric Company. Mr. Sowell received his Master and Bachelor of Science Degrees in Mathematics from Lamar University.

John R. Frank, Controller and Chief Accounting Officer, joined the Company in 1990. From 1989 until he joined Lomak in 1990, Mr. Frank was Vice President Finance of Appalachian Exploration, Inc. Prior thereto, he held the positions of Internal Auditor and Treasurer with Appalachian Exploration, Inc. beginning in 1977. Mr. Frank received his Bachelor of Arts Degree in Accounting and Management from Walsh College and attended graduate studies at the University of Akron.

Geoffrey T. Doke, Treasurer, joined the Company in 1991. He was appointed Treasurer in 1996. Previously, Mr. Doke served in the accounting department of Edisto Resources Corporation. Mr. Doke received his Bachelor of Business Administration Degree in Finance and International Business from Baylor University and his Master of Business Administration Degree from Case Western Reserve University.

The Lomak Board has established three committees to assist in the discharge of its responsibilities.

AUDIT COMMITTEE. The Audit Committee reviews the professional services provided by Lomak's independent public accountants and the independence of such accountants from management of Lomak. This Committee also reviews the scope of the audit coverage, the annual financial statements of Lomak and such other matters with respect to the accounting, auditing and financial reporting practices and procedures of Lomak as it may find appropriate or as have been brought to its attention. Messrs. Aikman, Dub and Guill members of the Audit Committee.

COMPENSATION COMMITTEE. The Compensation Committee reviews and approves executive salaries and administers bonus, incentive compensation and stock option plans of Lomak. This Committee advises and consults with management regarding pensions and other benefits and significant compensation policies and practices of Lomak. This Committee also considers nominations of candidates for corporate officer positions. The members of Compensation committee are Messrs. Aikman, Guill and Finkelson.

EXECUTIVE COMMITTEE. The Executive Committee reviews and authorizes actions required in the management of the business and affairs of Lomak, which would otherwise be determined by the Board, where it is not practicable to convene the full Board. One of the principal responsibilities of the Executive Committee will be to review and approve smaller acquisitions. The members of the Executive Committee are Messrs. Edelman, Finkelson and Pinkerton.

ITEM 11. COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Information with respect to executive compensation is incorporated herein by reference to the Proxy Statement for its 1997 annual meeting of stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information with respect to security ownership of certain beneficial owners and management is incorporated herein by reference to the Company's Proxy Statement for its 1997 annual meeting of stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information with respect to certain relationships and related transactions is incorporated herein by reference to the Company's Proxy Statement for its 1997 annual meeting of stockholders.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. and 2. Financial Statements and Financial Statement Schedules. The items listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

3. Exhibits.
The items listed on the accompanying index to exhibits are filed as part of this Annual Report on Form 10-K.

(b) Reports on Form 8-K.

The Company's Current Report on Form 8-K, dated April 19, 1996, as amended by Form 8-K/A, dated May 31, 1996.

The Company's Current Report on Form 8-K, dated February 26, 1997, as amended by Form 8-K/A, dated March 14, 1997.

(c) Exhibits required by Item 601 of Regulation S-K.
Exhibits required to be filed by the Company pursuant to Item 601 of Regulation S-K are contained in Exhibits listed in response to Item 14 (a)3, and are incorporated herein by reference.

(d) Financial Statement Schedules Required by Regulation S-X.
The items listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

SIGNATURES

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934, THE COMPANY HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED, THEREUNTO DULY AUTHORIZED.

Dated: March 21, 1997

LOMAK PETROLEUM, INC.

By: /s/ John H. Pinkerton

John H. Pinkerton
President

PURSUANT TO THE REQUIREMENTS OF THE SECURITIES EXCHANGE ACT OF 1934, THIS REPORT HAS BEEN SIGNED BELOW BY THE PERSONS ON BEHALF OF THE COMPANY AND IN THE CAPACITIES AND ON THE DATES INDICATED.

/s/ Thomas J. Edelman March 21, 1997	Thomas J. Edelman, Chairman and Chairman of the Board
/s/ John H. Pinkerton March 21, 1997	John H. Pinkerton, Chief Executive Officer, President and Director
/s/ Thomas W. Stoelk March 21, 1997	Thomas W. Stoelk, Chief Financial Officer and Vice President-Finance
/s/ John R. Frank March 21, 1997	John R. Frank, Chief Accounting Officer and Controller
/s/ Robert E. Aikman March 21, 1997	Robert E. Aikman, Director
/s/ Allen Finkelson March 21, 1997	Allen Finkelson, Director
/s/ Anthony V. Dub March 21, 1997	Anthony V. Dub, Director
/s/ Ben A. Guill March 21, 1997	Ben A. Guill, Director
/s/ C. Rand Michaels March 21, 1997	C. Rand Michaels, Vice Chairman and Director

LOMAK PETROLEUM, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES

(ITEM 14[a], [d])

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Exhibits

All other schedules have been omitted since the required information is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements or footnotes.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

THE BOARD OF DIRECTORS AND STOCKHOLDERS
LOMAK PETROLEUM, INC.

We have audited the accompanying consolidated balance sheets of Lomak Petroleum, Inc. (a Delaware corporation) as of December 31, 1995 and 1996, and the related consolidated statements of income, stockholders' equity and cash flows for 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 financial position of Lomak Petroleum, Inc. as of December 31, 1995 and 1996, and the results of its operations and its cash flows for the three years in the period ended December 31, 1996, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

Cleveland, Ohio,
February 14, 1997

LOMAK PETROLEUM, INC.

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT PER SHARE DATA)

	December 31, 1995	December 31, 1996
ASSETS		
Current assets		
Cash and equivalents	$ 3,047	$ 8,625
Accounts receivable	14,109	18,121
Marketable securities	953	7,658
Inventory and other	1,114	799
	19,223	35,203
Oil and gas properties, successful efforts method	210,073	282,519
Accumulated depletion	(33,371)	(53,102)
	176,702	229,417
Gas transportation and field service assets	23,167	21,139
Accumulated depreciation	(4,304)	(4,997)
	18,863	16,142
Other	-	1,785
	$ 214,788	$ 282,547
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 9,084	$ 14,433
Accrued liabilities	3,761	4,603
Accrued payroll and benefit costs	1,762	3,245
Current portion of debt (Note 4)	53	26
	14,660	22,307
Long-term debt (Note 4)	83,035	116,780
Deferred taxes (Note 10)	17,726	25,931
Commitments and contingencies (Note 6)		
Stockholders' equity (Notes 7 and 8)		
Preferred stock, $1 par, 4,000,000 shares authorized,		
7-1/2% convertible preferred, 200,000 issued (liquidation preference $5,000,000)	200	-
$2.03 convertible preferred, 1,150,000 issued (liquidation preference $28,750,000)	1,150	1,150
Common stock, $.01 par, 35,000,000 shares authorized, 13,322,738 and 14,750,537 issued	133	148
Capital in excess of par value	101,773	110,248
Retained earnings (deficit)	(4,013)	5,291
Unrealized gain on marketable securities	124	692
	99,367	117,529
	$ 214,788	$ 282,547

SEE ACCOMPANYING NOTES.

LOMAK PETROLEUM, INC.
CONSOLIDATED STATEMENTS OF INCOME
(IN THOUSANDS, EXCEPT PER SHARE DATA)

	Year Ended December 31,		
	1994	1995	1996
Revenues			
Oil and gas sales	$24,461	$37,417	$68,054
Field services	7,667	10,097	14,223
Gas transportation and marketing	2,195	3,284	5,575
Interest and other	471	1,317	3,386
	34,794	52,115	91,238
Expenses			
Direct operating	10,019	14,930	24,456
Field services	5,778	6,469	10,443
Gas transportation and marketing	490	849	1,674
Exploration	359	512	1,460
General and administrative	2,478	2,736	3,966
Interest	2,807	5,584	7,487
Depletion, depreciation and amortization	10,105	14,863	22,303
	32,036	45,943	71,789
Income before taxes	2,758	6,172	19,449
Income taxes			
Current	21	86	729
Deferred	118	1,696	6,105
	139	1,782	6,834
Net income	$ 2,619	$ 4,390	$12,615
Earnings per common share	$ 0.25	$ 0.31	$ 0.69
Weighted average shares outstanding	9,051	11,841	14,812

SEE ACCOMPANYING NOTES.

LOMAK PETROLEUM, INC.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(IN THOUSANDS)

	Preferred Stock		Common Stock			
	Shares	Par Value	Shares	Par Value	Capital in Excess of Par Value	Retained Earnings (Deficit)
Balance, December 31, 1993....	200	$ 200	8,309	$ 83	$ 41,768	$ (9,788)
Preferred dividends.........	-	-	-	-	-	(375)
Common issued...............	-	-	1,504	15	9,220	-
Common repurchased..........	-	-	(59)	(1)	(493)	-
Net income..................	-	-	-	-	-	2,619
Balance, December 31, 1994....	200	200	9,754	97	50,495	(7,544)
Preferred dividends.........	-	-	-	-	-	(731)
Common dividends............	-	-	-	-	-	(128)
Common issued...............	-	-	3,609	36	24,953	-
Common repurchased..........	-	-	(40)	-	(332)	-
$2.03 preferred issued......	1,150	1,150	-	-	26,657	-
Net income..................	-	-	-	-	-	4,390
Balance, December 31, 1995....	1,350	1,350	13,323	133	101,773	(4,013)
Preferred dividends.........	-	-	-	-	-	(2,454)
Common dividends............	-	-	-	-		(857)
Common issued...............	-	-	887	9	8,687	-
Common repurchased..........	-	-	(36)	-	(406)	-
Conversion of 7 1/2preferred..	(200)	(200)	577	6	194	-
Net income..................	-	-	-	-		12,615
Balance, December 31, 1996....	1,150	$ 1,150	14,751	$ 148	$ 110,248	$ 5,291

SEE ACCOMPANYING NOTES.

LOMAK PETROLEUM, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	1994	1995	1996
Cash flows from operations:			
Net income	$ 2,619	$ 4,390	$ 12,615
Adjustments to reconcile net income to net cash provided by operations:			
Depletion, depreciation and amortization	10,105	14,863	22,303
Deferred income taxes	118	1,335	6,105
Changes in working capital net of effects of businesses:			
Accounts receivable	3,106	(5,247)	(494)
Marketable securities	(534)	(296)	(5,264)
Inventory and other	(45)	278	137
Accounts payable	(2,126)	663	5,385
Accrued liabilities and payroll and benefit costs	(1,531)	1,778	781
Gain on sale of assets and other	(471)	(1,203)	(3,123)
Net cash provided by operations	11,241	16,561	38,445
Cash flows from investing:			
Acquisition of businesses, net of cash	(9,399)	-	(13,950)
Oil and gas properties	(22,251)	(69,992)	(59,137)
Additions to property and equipment	(813)	(9,102)	(1,250)
Proceeds on sale of assets	2,927	2,981	4,671
Net cash used in investing	(29,536)	(76,113)	(69,666)
Cash flows from financing:			
Proceeds from indebtedness	22,235	21,304	85,201
Repayments of indebtedness	(1,024)	(808)	(53,268)
Preferred stock dividends	(375)	(731)	(2,454)
Common stock dividends	-	(128)	(857)
Proceeds from Common stock issuance	830	10,590	8,315
Repurchase of common stock	(493)	(332)	(138)
Proceeds from Preferred stock issuance	-	27,807	-
Net cash provided by financing	21,173	57,702	36,799
Change in cash	2,878	(1,850)	5,578
Cash and equivalents at beginning of period	2,019	4,897	3,047
Cash and equivalents at end of period	$ 4,897	$ 3,047	$ 8,625
Supplemental disclosures of non-cash investing and financing activities			
Purchase of property and equipment financed with common stock	$ 7,694	$ 14,299	$ -
Conversion of 10% Convertible Subordinated Notes	464	-	-
Common stock issued in connection with benefit plans	228	100	381

SEE ACCOMPANYING NOTES.

Lomak Petroleum, Inc.
Notes to Consolidated Financial Statements

(1) ORGANIZATION AND NATURE OF BUSINESS

Lomak Petroleum, Inc. ("Lomak" or the "Company") is an independent oil company engaged in development, exploration and acquisition primarily in three core areas: Midcontinent, the Gulf Coast and Appalachia. Historically, the Company has increased its reserves and production through acquisitions, development and exploration of its properties. Over the past six years, 62 acquisitions have been consummated at a total cost of $249 million and approximately $39 million has been expended on development and exploration activities. As a result, proved reserves and production have each grown during this period at compound rates of 90% and 70% per annum, respectively. At December 31, 1996, proved reserves totaled 384 Bcfe, having a pre-tax present value at constant prices on that date of $492 million and a reserve life of approximately 14 years.

Effective January 1997, the Company acquired oil and gas properties from American Cometra, Inc. for a purchase price of $385 million, subject to adjustment. This transaction is more fully described in Note (15) Cometra Acquisition.

Lomak's objective is to maximize shareholder value through growth in its reserves, production, cashflow and earnings through a balanced program of development drilling and acquisitions, as well as, to a growing extent, exploration effort. In order to effectively implement its operating strategy, the Company has concentrated its activities in selected geographic areas. In each core area, the Company has established separate acquisition, engineering, geological, operating and other technical expertise. The Company believes that this geographic focus provides it with a competitive advantage in sourcing and evaluating new business opportunities within these areas, as well as providing economies of scale in developing and operating its properties.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

The accompanying financial statements include the accounts of the Company, all majority owned subsidiaries and its pro rata share of the assets, liabilities, income and expenses of certain oil and gas partnerships and joint ventures. Highly liquid temporary investments with an initial maturity of ninety days or less are considered cash equivalents.

OIL AND GAS PROPERTIES

The Company follows the successful efforts method of accounting for oil and gas properties. Exploratory costs which result in the discovery of reserves and the cost of development wells are capitalized. Geological and geophysical costs, delay rentals and costs to drill unsuccessful exploratory wells are expensed. Depletion is provided on the unit-of-production method. Oil is converted to Mcfe at the rate of six Mcf per barrel. The depletion rates per Mcfe were $.74, $.73 and $.73 in 1994, 1995 and 1996, respectively. Approximately $4.3 million, $12.2 million and $22.8 million of oil and gas properties were not subject to amortization as of December 31, 1994, 1995 and 1996, respectively. These costs are assessed periodically to determine whether their value has been impaired, and if impairment is indicated, the excess costs are charged to expense.

Effective January 1, 1996, the Company adopted Statement of Financial Accounting Standards No. 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," which establishes accounting standards for the impairment of long-lived assets, certain identifiable intangibles and goodwill. SFAS No. 121 requires a review for impairment whenever circumstances indicate that the carrying amount of an asset may not be recoverable. In performing the review for recoverability, the Company would estimate future cash flows (undiscounted and without interest charges) expected to result from the use of an asset and its eventual disposition. Impairment is recognized only if the carrying amount of an asset is greater than its expected future cash flows. The amount of the impairment is based on the estimated fair value of the asset. The initial adoption of SFAS No. 121 had no impact on the Company.

GAS IMBALANCES

The Company uses the sales method to account for gas imbalances. Under the sales method, revenue is recognized based on cash received rather than the proportionate share of gas produced. Gas imbalances at year end 1996 and 1995 were not material.

GAS TRANSPORTATION AND FIELD SERVICE ASSETS

The Company owns and operates approximately 1,900 miles of gas gathering lines in proximity to its principal gas properties. Depreciation is calculated on the straight-line method based on estimated useful lives ranging from four to fifteen years.

The Company receives fees for providing field related services. These fees are recognized as earned. Depreciation is calculated on the straight-line method based on estimated useful lives ranging from one to six years, except for buildings which are being depreciated over ten to fifteen year periods.

During 1996 the majority of the Company's brine disposal and well servicing activities were based in Oklahoma. In December 1996, the Company sold its brine disposal and well servicing activities in Oklahoma for $2.7 million and recorded a gain on sale of approximately $1.2 million which is included in interest and other income. In 1994, the Company sold substantially all of its brine disposal and well servicing assets located in Appalachia for approximately $1.8 million.

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.

NATURE OF BUSINESS

The Company operates in an environment with many financial and operating risks, including, but not limited to, the ability to acquire additional economically recoverable oil and gas reserves, the inherent risks of the search for, development of and production of oil and gas, the ability to sell oil and gas at prices which will provide attractive rates of return, and the highly competitive nature of the industry and worldwide economic conditions. The Company's ability to expand its reserve base and diversify its operations is also dependent upon obtaining the necessary capital through operating cash flow, borrowings or the issuance of additional equity.

MARKETABLE SECURITIES

The Company adopted Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Under Statement No. 115, debt and marketable equity securities are required to be classified in one of three categories: trading, available-for-sale, or held to maturity. The Company's equity securities qualify under the provisions of Statement No. 115 as available-for-sale. Such securities are recorded at fair value, and unrealized holding gains and losses, net of the related tax effect, are reflected as a separate component of stockholders' equity. A decline in the market value of an available-for-sale security below cost that is deemed other than temporary is charged to earnings and results in the establishment of a new cost basis for the security. Realized gains and losses are determined on the specific identification method and are reflected in income.

DEBT ISSUANCE COSTS

Expenses associated with the issuance of the 6% Convertible Subordinated Debentures Due 2007 are included in Other Assets on the accompanying balance sheet and are being amortized on the interest method over the term of the debentures.

EARNINGS PER COMMON SHARE

Net income per share is computed by subtracting preferred dividends from net income and dividing by the weighted average number of common and common equivalent shares outstanding. The calculation of fully diluted earnings per share assumes conversion of convertible securities when the result would be dilutive. Outstanding options and warrants are included in the computation of net income per common share when their effect is dilutive.

RECLASSIFICATIONS

Certain reclassifications have been made to prior period presentation to conform with current period classifications.

(3) ACQUISITION AND DEVELOPMENT

All of the Company's acquisitions have been accounted for as purchases. The purchase prices were allocated to the assets acquired based on the fair value of such assets and liabilities at the respective acquisition dates. The acquisitions were funded by working capital, advances under a revolving credit facility and the issuance of equity.

During 1996, the Company acquired oil and gas properties, equipment and acreage from Bannon Energy, Incorporated for approximately $37.0 million and acquired Eastern Petroleum Company for approximately $13.7 million. The Bannon interests included 270 producing properties located in Texas, Oklahoma, New Mexico and Wyoming. Eastern Petroleum Company owned interests in oil and gas properties, equipment and acreage in Ohio.

In 1995, the Company acquired oil gas properties, equipment and acreage from Transfuel, Inc. for $21 million, which included cash and approximately $800,000 of Common Stock, and from Parker & Parsley Petroleum Company for $20.2 million. The Transfuel interests included developed and undeveloped properties in Ohio, Pennsylvania and New York. The Parker & Parsley interests included developed and undeveloped properties in Pennsylvania and Ohio.

In 1994, the Company acquired Red Eagle Resources Corporation for $46.5 million. Included in this amount were 2.8 million shares of Common Stock valued at approximately $16.9 million to the acquired company's shareholders. Red Eagle's assets included 370 producing wells, equipment and acreage located primarily in the Okeene Field of Oklahoma's Anadarko Basin. In addition, the Company purchased Grand Banks Energy Company for $3.7 million and Gillring Oil Company for $11.5 million. Grand Bank's assets included interests in 182 producing properties located in west Texas and Gillring's assets included $5.2 million of working capital and interests in 106 producing properties located in south Texas.

UNAUDITED PRO FORMA FINANCIAL INFORMATION

The following table presents unaudited pro forma operating results as if the transactions had occurred at the beginning of each period presented. The pro forma operating results include the following acquisitions, all of which were accounted for as purchase transactions; (i) the purchase by the Company of certain oil and gas properties from a subsidiary of Parker & Parsley Petroleum, Co., (ii) the purchase by the Company of certain oil and gas properties from Transfuel, Inc., (iii) the purchase by the Company of certain oil and gas properties from Bannon Energy Incorporated, (iv) the private placement of 1.15 million shares of Convertible Preferred Stock and the application of the net proceeds therefrom and (v) the private placement of 1.8 million shares of Common Stock and (vi) the private placement of $55 million of 6% Convertible Subordinated Debentures Due 2007 and the application of the net proceeds therefrom.

	Year ended December 31,	
	1995	1996
	(in thousands except per share data)	
Revenues.......................	$ 69,664	$ 92,823
Net income.....................	6,808	12,481
Earnings per share.............	0.31	0.68
Total assets....................	252,442	282,547
Stockholders' equity............	99,367	117,529

The pro forma operating results have been prepared for comparative purposes only. They do not purport to present actual operating results that would have been achieved had the acquisitions and financings been made at the beginning of each period presented or to necessarily be indicative of future results of operations.

(4) INDEBTEDNESS

The Company had the following debt outstanding as of the dates shown. Interest rates at December 31, 1996 are shown parenthetically:

	December 31,	
	1995	1996
	(in thousands)	
Bank credit facility (6.7%).....................	$ 83,035	$ 61,355
6% Convertible Subordinated Debentures..........	-	55,000
Other (5.9% - 7.0%).............................	53	451
	83,088	116,806
Less amounts due within one year................	53	26
Long-term debt, net.............................	$ 83,035	$ 116,780

The Company maintains a $250 million revolving bank credit facility. The facility provides for a borrowing base which is subject to semi-annual redeterminations. At December 31, 1996, the borrowing base on the credit facility was $150 million. The facility bears interest at prime rate of LIBOR plus 0.75% to 1.25% depending upon the percentage of the borrowing base drawn. Interest is payable quarterly and the loan is payable in sixteen quarterly installments beginning February 1, 1999. A commitment fee of 3/8% of the undrawn balance is payable quarterly. It is the Company's policy to extend the term period of the credit facility annually.

As described in Note (15), the revolving bank credit facility was amended and expanded in connection with the financing of the Cometra Acquisition (the "Amended Credit Facility"). The Amended Credit Facility is secured by first priority security interests in (i) existing mortgaged oil and gas properties of the Company, including the Cometra Properties, (ii) all accounts receivable, inventory and intangibles of the Company and the subsidiaries guaranteeing the Amended Credit Facility, and (iii) all of the capital stock of the Company's direct and indirect subsidiaries. Substantially all of the assets of the Company will be pledged as collateral if, on May 15, 1997, the Borrowing Base and amounts outstanding under the Amended Credit Facility have not been reduced to $325 million. Such security interests will be released upon the (i) reduction of the amounts outstanding under the Amended Credit Facility to $325 million (or the then determined Borrowing Base) and (ii) issuance of $65 million of Common Stock and/or the sale of Company assets in excess of the Borrowing Base value attributable to such assets as agreed by the lenders.

The 6% Convertible Subordinated Debentures Due 2007 (the "Debentures") are convertible at the option of the holder at any time prior to maturity into shares of the Company's Common Stock, at a conversion price of $19.25 per share, subject to adjustment in certain events. Interest is payable semi-annually. The Debentures will mature in 2007 and are not redeemable prior to February 1, 2000. The Debentures are unsecured general obligations of the Company subordinated to all senior indebtedness, as defined.

The debt agreements contain various covenants relating to net worth, working capital maintenance and financial ratio requirements. The Company is in compliance with these various covenants as of December 31,1996. Interest paid during the years ended December 31, 1994, 1995 and 1996 totaled $2.8 million, $4.9 million and $7.5 million, respectively.

Maturities of indebtedness as of December 31, 1996 were as follows (in thousands):

1997............................	$ 26
1998............................	413
1999............................	15,354
2000............................	15,339
2001............................	15,339
Remainder.......................	70,335
	$ 116,806

(5) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES:

The Company's financial instruments include cash and equivalents, accounts receivable, accounts payable, debt obligations, commodity and interest rate futures, options, and swaps. The book value of cash and equivalents, accounts receivable and payable and short term debt are considered to be representative of fair value because of the short maturity of these instruments. The Company believes that the carrying value of its borrowings under its bank credit facility approximates their fair value as they bear interest at rates indexed to LIBOR. The Company's accounts receivable are concentrated in the oil and gas industry. The Company does not view such a concentration as an unusual credit risk. The Company has recorded an allowance for doubtful accounts of $306,000 and $450,000 at December 31, 1995 and 1996, respectively.

A portion of the Company's crude oil and natural gas sales are periodically hedged against price risks through the use of futures, option or swap contracts. The gains and losses on these instruments are included in the valuation of the production being hedged in the contract month and are included as an adjustment to oil and gas revenue. The Company also manages interest rate risk on its credit facility through the use of interest rate swap agreements. Gains and losses on swap agreements are included as an adjustment to interest expense.

The following table sets forth the book value and estimated fair values of the Company's financial instruments:

	December 31, 1995		December 31, 1996	
	(In thousands)			
	Book Value	Fair Value	Book Value	Fair Value
Cash and equivalents....................	$ 3,047	$ 3,047	$ 8,625	$ 8,625
Marketable securities...................	829	953	6,966	7,658
Long-term debt..........................	(83,088)	(83,088)	(116,806)	(116,806)
Commodity swaps.........................	-	93	-	(1,051)
Interest rate swaps.....................	-	375	-	81

At December 31, 1996, the Company had open contracts for oil and gas price swaps of 300,000 barrels and 155,000 Mcfs. The swap contracts are designed to set average prices ranging from $22.10 to $22.76 per barrel and $2.04 per Mcf. While these transactions have no carrying value, their fair value, represented by the estimated amount that would be required to terminate the contracts, was a net cost of approximately $1,051,000 at December 31, 1996. These contracts expire monthly through April 1997. The gains or losses on the Company's hedging transactions is determined as the difference between the contract price and the reference price, generally closing prices on the New York Mercantile Exchange. The resulting transaction gains and losses are determined monthly and are included in net income in the period the hedged production or inventory is sold. Net gains or (losses) relating to these derivatives for the years ended December 31, 1994, 1995 and 1996 approximated $-0-, $217,000 and $(724,000) respectively.

Interest rate swap agreements, which are used by the Company in the management of interest rate exposure, is accounted for on the accrual basis. Income and expense resulting from these agreements are recorded in the same category as expense arising from the related liability. Amounts to be paid or received under interest rate swap agreements are recognized as an adjustment to expense in the periods in which they accrue. At December 31, 1996, the Company had $60 million of borrowings subject to three interest rate swap agreements at rates of 5.25%, 5.49% and 5.64% through July 1997, October 1997 and October 1998, respectively. The interest rate swaps may be extended at the counterparties' option for two years. The agreements require that the Company pay the counterparty interest at the above fixed swap rates and requires the counterparty to pay the Company interest at the 30-day LIBOR rate. The closing 30-day LIBOR rate on December 31, 1996 was 5.53%. The fair value of the interest rate swap agreements at December 31, 1996, is based upon current quotes for equivalent agreements.

These hedging activities are conducted with major financial or commodities trading institutions which management believes entail acceptable levels of market and credit risks. At times such risks may be concentrated with certain counterparties or groups of counterparties. The credit worthiness of counterparties is subject to continuing review and full performance is anticipated.

(6) COMMITMENTS AND CONTINGENCIES

The Company is involved in various legal actions and claims arising in the ordinary course of business. In the opinion of management, such litigation and claims will be resolved without material adverse effect on the Company's financial position.

The Company recently received notice from two parties, each of whom claims that it is entitled to fees from the Company based upon a Yemen oil concession that they claim Red Eagle Resources Corporation received in August 1992, which was prior to the acquisition of Red Eagle by the Company. Based upon the Company's examination of the available documentation relevant to such claims, the Company believes that the claims are without merit because the claimed oil concession was never obtained in Yemen. The Company has requested further documentation from the two parties with respect to their claims but no such documentation has yet been provided. The claims are for approximately $4.0 million in the aggregate (including the value of approximately 70,000 shares of Common Stock that would be required to be issued if the oil concession had been obtained). To date, no proceedings have been commenced with respect to either of these claims.

The Company leases certain office space and equipment under cancelable and non-cancelable leases, most of which expire within 10 years and may be renewed by the Company. Rent expense under such arrangements totaled $202,000, $335,000 and $208,000 in 1994, 1995 and 1996 respectively. Future minimum rental commitments under non-cancelable leases are as follows (in thousands):

1997	$ 270
1998	270
1999	233
2000	195
2001	210
2002 and thereafter	270
	$ 1,448

(7) EQUITY SECURITIES

In 1993, $5,000,000 of 7-1/2% cumulative convertible exchangeable preferred stock (the "7-1/2% Preferred Stock") was privately placed. In 1996, the Company exercised it's option and converted the 7-1/2% Preferred Stock into 576,945 shares of Common Stock.

In November 1995, the Company sold 1,150,000 shares of $2.03 convertible exchangeable preferred stock (the "$2.03 Preferred Stock") for $28.8 million. The $2.03 Preferred Stock is convertible into the Company's common stock at a conversion price of $9.50 per share, subject to adjustment in certain events. The $2.03 Preferred Stock is redeemable, at the option of the Company, at any time on or after November 1, 1998, at redemption prices beginning at 105%. At the option of the Company, the $2.03 Preferred Stock is exchangeable for the Company's 8-1/8% convertible subordinated notes due 2005. The notes would be subject to the same redemption and conversion terms as the $2.03 Preferred Stock

In December 1995, the Company privately placed 1.2 million shares of its Common Stock for $10.2 million to a state sponsored retirement plan. In April 1996, the Company privately placed 600,000 shares of its Common Stock to a limited number of institutional investors for approximately $6.9 million. Warrants to acquire 40,000 shares of common stock were exercised in October 1996. Additionally, warrants to acquire 20,000 shares of Common Stock at a price of $12.88 per share were outstanding at December 31, 1996 and will expire in May 1999.

(8) STOCK OPTION AND PURCHASE PLAN

The Company maintains a Stock Option Plan which authorizes the grant of options of up to 2.0 million shares of Common Stock. However, no new options may be granted which would result in their being outstanding aggregate options exceeding 10% of the Company's common shares outstanding plus those shares issuable under convertible securities. Under the plan, incentive and non-qualified options may be issued to officers, key employees and consultants. The plan is administered by the Compensation Committee of the Board. All options issued under the plan vest 30% after one year, 60% after two years and 100% after three years. The following is a summary of stock option activity:

	Number of Options			Exercise Price Range Per Share
	1994	1995	1996	
Outstanding at beginning of year........	428,983	680,483	977,149	$3.38 - $ 9.38
Granted..................................	298,500	342,000	378,500	10.50 - 13.88
Canceled...............................	(16,000)	(12,000)	(7,950)	7.00 - 10.50
Exercised..............................	(31,000)	(33,334)	(115,250)	3.38 - 8.25
Outstanding at end of year..............	680,483	977,149	1,232,499	$3.38 - $13.88

In 1994, the stockholders approved the 1994 Outside Directors Stock Option Plan (the "Directors Plan"). Only Directors who are not employees of the Company are eligible under the Directors Plan. The Directors Plan covers a maximum of 200,000 shares. At December 31, 1996, 76,000 options were outstanding under the Directors Plan of which 16,800 were exercisable as of that date. The exercise price of the options ranges from $7.75 to $13.88 per share.

In 1994, the stockholders approved the 1994 Stock Purchase Plan (the "1994 Plan") which authorizes the sale of up to 500,000 shares of Common Stock to officers, directors, key employees and consultants. Under the Plan, the right to purchase shares at pricing ranging from 50% to 85% of market value may be granted. The Company had a 1989 Stock Purchase Plan (the "1989 Plan") which was identical to the 1994 Plan except that it covered 333,333 shares. Upon adoption of the 1994 Plan, the 1989 Plan was terminated. The plans are administered by the Compensation Committee of the Board. During the year ended December 31, 1996, the Company sold 100,000 unregistered shares of Common Stock to officers and outside directors for an aggregate amount of approximately $966,000.

The Company has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans. Had compensation cost for the Corporation's two stock option plans been determined based on the fair value at the grant date for awards in 1995 and 1996 consistent with the provisions of SFAS No. 123, the Company's net earnings and earnings per share would have been reduced to the pro forma amounts indicated below:

	1995	1996
	(in thousands, except per share data)	
Net earnings-- as reported	$4,390	$12,615
Earnings per share-- as reported	$ 0.31	$ 0.69
Net earnings-- pro forma	$4,081	$11,996
Earnings per share--pro forma	$ 0.28	$ 0.64

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants: dividend yield of 1%; expected volatility of 38%; risk-free interest rate of 6%; and expected lives of 4 years.

(9) BENEFIT PLAN

The Company maintains a 401(K) Plan for the benefit of its employees. The Plan permits employees to make contributions on a pre-tax salary reduction basis. The Company makes discretionary contributions to the Plan. Company contributions for 1994, 1995 and 1996 were $226,000, $346,000 and $548,000 respectively. The Company has no other employment benefit plans.

(10) INCOME TAXES

Federal income tax expense was $139,000, $1.8 million and $6.8 million for the years 1994, 1995 and 1996, respectively. The current portion of the income tax provision represents alternative minimum tax currently payable. A reconciliation between the statutory federal income tax rate and the Company's effective federal income tax rate is as follows:

	1994	1995	1996
Statutory tax rate	34%	34%	34%
Realization of valuation allowance	(29)	(5)	-
Other	-	-	1
Effective tax rate	5%	29%	35%
Income taxes paid	$ 47,500	$ 60,000	$590,000

The Company follows FASB Statement No. 109, "Accounting for Income Taxes". Under Statement 109, the liability method is used in accounting for income taxes. 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.

Significant components of the Company's deferred tax liabilities and assets are as follows (in thousands):

	December 31,	
	1995	1996
Deferred tax liabilities:		
Depreciation	$ 29,130	$ 31,726
Deferred tax assets:		
Net operating loss carryforwards	6,193	2,625
Percentage depletion carryforward	4,388	2,589
AMT credits and other	863	621
Total deferred tax assets	11,444	5,835
Valuation allowance for deferred tax assets	(40)	(40)
Net deferred tax assets	$ 11,404	$ 5,795
Net deferred tax liabilities	$ 17,726	$ 25,931

Due to uncertainty as to the company's ability to realize the tax benefit, a valuation allowance was established for the full amount of the net deferred tax assets. In 1995, income taxes were reduced from the statutory rate of 34% by approximately $0.3 million through realization of a portion of the valuation allowance, resulting in $40,000 of the allowance remaining at each of December 31, 1995 and 1996.

The Company has entered into several business combinations accounted for as purchases. In connection with these transactions, deferred tax assets and liabilities of $7.7 million and $23.8 million respectively, were recorded. In 1996 the Company acquired Eastern Petroleum Company in a taxable business combination accounted for as a purchase. A net deferred tax liability of $2.1 million was recorded in the transaction.

As a result of the Company's issuance of equity and convertible debt securities, it experienced a change in control during 1988 as defined by Section 382 of the Internal Revenue Code. The change in control placed limitations to the utilization of net operating loss carryovers. At December 31, 1996, the Company had available for federal income tax reporting purposes net operating loss carryovers of approximately $7.5 million which are subject to annual limitations as to their utilization and otherwise expire between 1997 and 2010, if unused. The Company has alternative minimum tax net operating loss carryovers of $6.6 million which are subject to annual limitations as to their utilization and otherwise expire from 1997 to 2009 if unused. The Company has statutory depletion carryover of approximately $3.2 million and an alternative minimum tax credit carryover of approximately $500,000. The statutory depletion carryover and alternative minimum tax credit carryover are not subject to limitation or expiration.

(11) MAJOR CUSTOMERS

The Company markets its oil and gas production on a competitive basis. The type of contract under which gas production is sold varies but can generally be grouped into three categories: (a) life-of-the-well; (b) long-term (1 year or longer); and (c) short-term contracts which may have a primary term of one year, but which are cancelable at either party's discretion in 30-120 days. Approximately 60% of the Company's gas production is currently sold under market sensitive contracts which do not contain floor price provisions. For the year ended December 31, 1996, no one customer accounted for more than 10% of the Company's total oil and gas revenues. Management believes that the loss of any one customer would not have a material adverse effect on the operations of the Company. Oil is sold on a basis such that the purchaser can be changed on 30 days notice. The price received is generally equal to a posted price set by the major purchasers in the area. The Company sells to oil purchasers on a basis of price and service.

(12) OIL AND GAS ACTIVITIES

The following summarizes selected information with respect to oil and gas producing activities:

	Year Ended December 31, 1994	1995	1996
		(in thousands)	
Oil and gas properties:			
Subject to amortization	$ 129,082	$ 197,826	$ 259,681
Not subject to amortization	4,291	12,247	22,838
Total	133,373	210,073	282,519
Accumulated depletion amortization	(20,409)	(33,371)	(53,102)
Net oil and gas properties	$ 112,964	$ 176,702	$ 229,417
Costs incurred:			
Acquisition	$ 59,501	$ 69,244	$ 63,579
Development	9,518	9,968	12,536
Exploration	192	216	2,025
Total costs incurred	$ 69,211	$ 79,428	$ 78,140

(13) RELATED PARTY TRANSACTIONS

Mr. Edelman, Chairman of the Company, is also a shareholder of Snyder Oil Corporation ("SOCO"), and until his resignation in February 1997, was an executive officer of SOCO. At December 31, 1996, Mr. Edelman owned 5.7% of the Company's Common Stock. In 1995, the Company acquired SOCO's interest in certain wells located in Appalachia for $4 million. The price was determined based on arms-length negotiations through third-party broker retained by SOCO. Subsequent to the transaction, the Company and SOCO no longer hold interests in any of the same properties.

During 1995, the Company incurred fees of $145,000 to the Hawthorne Company in connection with acquisitions. Mr. Aikman, a director of the Company, is an executive officer and a principal owner of the Hawthorne Company. The fees were consistent with those paid by the Company to third parties for similar services.

(14) UNAUDITED SUPPLEMENTAL RESERVE INFORMATION

The Company's proved oil and gas reserves are located in the United States. Proved reserves are those quantities of crude oil and natural gas which, upon analysis of geological and engineering data, can with reasonable certainty be recovered in the future from known oil and gas reservoirs. Proved developed reserves are those proved reserves which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage.

QUANTITIES OF PROVED RESERVES

	Crude Oil (Bbls)	Natural Gas (Mcf)
	(in thousands)	
Balance, December 31, 1993	4,539	74,563
Revisions	15	630
Extensions, discoveries and additions	15	6,605
Purchases	4,599	75,698
Sales	(79)	(1,130)
Production	(640)	(6,996)
Balance, December 31, 1994	8,449	149,370
Revisions	255	(3,513)
Extensions, discoveries and additions	475	10,076
Purchases	2,618	90,575
Sales	(21)	(1,150)
Production	(913)	(12,471)
Balance, December 31, 1995	10,863	232,887
Revisions	280	(7,545)
Extensions, discoveries and additions	952	16,696
Purchases	3,884	86,022
Sales	(236)	(11,235)
Production	(1,068)	(21,231)
Proved developed reserves	14,675	295,594
December 31, 1994	6,430	97,251
December 31, 1995	8,880	174,958
December 31, 1996	10,703	207,601

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" (Standardized Measure) is a disclosure requirement under Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities". The Standardized Measure does not purport to present the fair market value of proved oil and gas reserves. This would require consideration of expected future economic and operating conditions, which are not taken into account in calculating the Standardized Measure.

Future cash inflows were estimated by applying year end prices to the estimated future production less estimated future production costs based on year end costs. Future net cash inflows were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

STANDARDIZED MEASURE

	As of December 31		
	1994	1995	1996
	(in thousands)		
Future cash inflows	$ 457,048	$ 729,566	$ 1,393,338
Future costs:......................................			
Production....................................	(133,972)	(256,374)	(365,753)
Development...................................	(52,102)	(60,554)	(86,192)
Future net cash flows..............................	270,974	412,638	941,393
Income taxes.......................................	(59,950)	(102,108)	(271,023)
Total undiscounted future net cash flows...........	211,024	310,530	670,370
10% discount factor................................	(91,475)	(136,480)	(319,481)
Standardized measure...............................	$ 119,549	$ 174,050	$ 350,889

CHANGES IN STANDARDIZED MEASURE

	For the year ended December 31		
	1994	1995	1996
	(in thousands)		
Standardized measure, beginning of year	$ 53,751	$ 119,549	$ 174,050
Revisions:...			
Prices..	4,224	(4,100)	151,508
Quantities....................................	2,240	2,267	(6,762)
Estimated future development cost.............	-	(5,238)	(2,971)
Accretion of discount.........................	6,512	15,054	22,924
Income taxes..................................	(19,624)	(24,200)	(86,095)
Net revisions.................................	(6,648)	(16,217)	78,604
Purchases..	84,836	87,741	125,871
Extensions, discoveries and additions..............	2,402	7,419	22,816
Production...	(14,442)	(22,487)	(43,598)
Sales..	(350)	(1,955)	(6,854)
Standardized measure, end of year..................	$ 119,549	$ 174,050	$ 350,889

(15) COMETRA ACQUISITION

Effective January 1, 1997, the Company acquired oil and gas properties located in West Texas, South Texas and the Gulf of Mexico (the "Cometra Properties") from American Cometra, Inc. ("Cometra") for a purchase price of $385 million, subject to adjustment (the "Cometra Acquisition"). The Cometra Acquisition increases the Company's pro forma proved reserves at December 31, 1996 by 68% to 644 Bcfe and increases its Present Value by 98% to $974 million. The Cometra Properties, located primarily in the Company's core operating areas, include 515 producing wells, and additional development and exploration potential on approximately 150,000 gross acres (90,000 net acres). In addition, the Cometra Properties include gas pipelines, a 25,000 Mcf/d gas processing plant and an above-market gas contract with a major Texas gas utility covering approximately 30% of the current production from the Cometra Properties.

The Company will finance the cash portion of the purchase price with $221 million of borrowings through expansion of its bank credit facility (the "Amended Credit Facility") and the issuance to Cometra of a $134 million non-interest bearing promissory note due March 31, 1997, which is secured by a bank letter of credit. The promissory note will be repaid at maturity through borrowings under the Amended Credit Facility. The Amended Credit Facility will enable the Company to obtain revolving credit loans and issue letters of credit from time to time in an aggregate amount not to exceed $400 million initially. Availability under the Amended Credit Facility was reduced to $300 million upon the consummation of the Offerings. The Amended Credit Facility provides for a Borrowing Base which is subject to semi-annual determinations and certain other redeterminations. Security obligations in place with the Credit Agreement were released upon the consummation of the Offerings on March 14, 1997.

The Amended Credit Facility bears interest at either the Alternate Base Rate (as defined) plus a margin ranging from 0% to 0.25% or the Eurodollar loan rate plus margin ranging from 0.625% to 1.125%. Interest is payable quarterly and the Amended Credit Facility matures in February 2002.

The Amended Credit Facility includes various covenants that require, among other things, that the Company (i) maintain a minimum consolidated tangible net worth of at least $100 million plus 90% of the net proceeds from the Common Stock offering described below and 50% of the net proceeds from any subsequent equity offering; (ii) maintain a ratio of EBITDA to consolidated interest expense on total debt for each period of four consecutive fiscal quarters of at least 2.5 to 1.0; and (iii) not make restricted payments (defined as dividends, distributions or guarantees to third parties or the retirement, repurchase or prepayment prior to the scheduled maturity of its subordinated debt) in an aggregate amount in any one fiscal year in excess of $5 million plus 50% of the net proceeds from equity offerings subsequent to the Common Stock offering described below and 50% of the Company's consolidated net income earned after January 1, 1997. In addition, the Amended Credit Facility will restrict the ability of the Company to dispose of assets, incur additional indebtedness, repay other indebtedness or amend other debt instruments, create liens on assets, make investments or acquisitions, engage in mergers or consolidations, make capital expenditures or engage in certain transactions with affiliates.

In January 1997, the Company filed a registration statement with the Securities and Exchange Commission as amended, the registration statement covers the sale of 4 million shares of Common Stock and $125 million aggregate principal amount of ten year senior subordinated notes. On March 14, 1997, the Offerings were consummated with the Company receiving proceeds of approximately $186 million, after deducting underwriting discounts and estimated expenses. The proceeds from the Offerings were used to repay indebtedness incurred under the Amended Credit Facility in connection with the Cometra Acquisition. The notes will be guaranteed by all of the subsidiaries of the Company and each guarantor is a wholly owned subsidiary of the Company. The guarantees are full, unconditional and joint and several, and separate financial statements of each guarantor are not presented because they are included in the consolidated financial statements of the Company and management has concluded that they provide no additional benefits.

UNAUDITED PRO FORMA FINANCIAL INFORMATION

The following table presents unaudited pro forma operating results as if the Cometra Acquisition had occurred as of January 1, 1996. The pro forma operating results also include the following acquisitions, all of which were accounted for as purchase transactions: (i) the purchase by the Company of certain oil and gas properties from Bannon Energy Incorporated, (ii) the private placement of 600,000 shares of Common Stock and (iii) the private placement of $55 million of 6% Convertible Subordinated Debentures Due 2007 and the application of the net proceeds therefrom and (iv) the conversion of the Company's 7 1/2% Convertible Exchangeable Preferred Stock into Common Stock. Additionally, the unaudited pro forma operating results give effect to the sale of 4 million shares of Common Stock and $125 million aggregate principal amount of ten year senior subordinated notes.

UNAUDITED PRO FORMA FINANCIAL INFORMATION-CONTINUED

	YEAR ENDED DECEMBER 31, 1996
	(IN THOUSANDS)
Revenues:	
Oil and gas sales	$ 130,508
Field services	14,223
Gas transportation and marketing	24,326
Interest and other	3,386
	172,443
Expenses:	
Direct operating	39,394
Field services	10,443
Gas transportation and marketing	13,152
Exploration	1,460
General and administrative	3,966
Interest	30,957
Depletion, depreciation and amortization	44,389
	143,761
Earnings before income taxes	28,682
Income taxes	10,038
Net income	$ 18,644
Earnings per common share	$ 0.80

BALANCE SHEET DATA (AT DECEMBER 31, 1996):

Cash and equivalents	$ 8,625
Total assets	671,597
Long-term debt	411,756
Stockholders' equity	211,629

LOMAK PETROLEUM, INC.

INDEX TO EXHIBITS

(Item 14[a 3])

Exhibit No.	Description
3.1(a)	Certificate of Incorporation of Lomak dated March 24, 1980.(1)
3.1(b)	Certificate of Amendment of Certificate of Incorporation dated July 22, 1981.(1)
3.1(c)	Certificate of Amendment of Certificate of Incorporation dated September 8, 1982.(1)
3.1(d)	Certificate of Amendment of Certificate of Incorporation dated December 28, 1988.(1)
3.1(e)	Certificate of Amendment of Certificate of Incorporation dated August 31, 1989.(1)
3.2	Current By-Laws of Lomak.(1)
4	Specimen certificate of Lomak Petroleum, Inc. Common Stock.(1)
10.1(a)	Financial Restructuring Agreement dated September 29, 1988 between Lomak and Snyder Oil Corporation ("SOCO").(1)
10.1(b)	Loan Agreement dated September 29, 1988 between Lomak Petroleum (Ohio), Inc., SOCO and MBank Fort Worth N.A. and Second Amendments thereto.(1)
10.1(c)	Purchase and Sale Agreement dated February 28, 1989 between Lomak Petroleum (Ohio), Inc., Snyder Operating Partnership L.P. and Snyder Oil Partners L.P.(1)
10.1(d)	Incentive and Non-Qualified Stock Option Plan dated March 13, 1989.(1)
10.1(e)	Advisory Agreement dated September 29, 1988 between Lomak and SOCO.(1)
10.1(f)	401(k) Plan Document and Trust Agreement effective January 1, 1989.(1)
10.1(g)	1989 Stock Purchase Plan.(1)
10.1(h)	Purchase Agreement dated as of May 31, 1990 by and between Ameritrust Company National Association and Lomak [Incorporated by reference to Lomak's Form 8-K dated May 31, 1990].(2)
10.1(i)	Securities Purchase Agreement dated February 21, 1991 by and among the Company, Latoka and the selling securities holders of Latoka. (3)
10.1(j)	Asset Purchase Agreement dated February 28, 1991 between the Company and Latoka. (1)

10.1(k)	Proxies from Latoka Shareholders.(1)
10.1(l)	Lease Agreement dated September 1, 1986 between Three Lincoln Centre - A Joint Venture and Strong Corporation.(4)
10.1(m)	Strong 1986-A Ltd., Agreement of Limited Partnership.(4)
10.1(n)	Strong 1986-A Ltd. Certificate of Limited Partnership.(4)
10.1(o)	Letter Agreement dated December 4, 1987 regarding $600,000.00 loan by Latoka, Inc., as borrower, to Premier Bank, as lender.(4)
10.1(p)	Promissory Note dated December 4, 1987 regarding $600,000.00 loan by Latoka, Inc., as borrower, to Premier Bank, as lender.(4)
10.1(q)	Estoppel Certificate of Borrower dated December 4, 1987 regarding $600,000.00 loan by Latoka, Inc., as borrower, to Premier Bank, as lender.(4)
10.1(r)	Collateral Mortgage and Collateral Chattel Mortgage Note, Pledge Agreement and Collateral Mortgage and Collateral Mortgage dated December 4, 1987 regarding $600,000.00 loan by Latoka, Inc., as borrower, to Premier Bank, as lender.(4)
10.1(s)	Form for Deed of Trust, Security Agreement and Financing Statement (with Assignment of Production) dated December 4, 1987 regarding $600,000.00 loan by Latoka, Inc., as borrower, to Premier Bank, as lender.(4)
10.1(t)	Modification Agreement dated June 24, 1988 between Premier Bank, N.A. and Latoka, Inc.(4)
10.1(u)	Form of Warrant Agreement issued by Xenda Corporation.(5)
10.1(v)	Underwriters Warrant dated as of February 25, 1988 between Xenda Corporation and Capital First Securities, Inc. (5)
10.1(w)	Selling and Agency Agreement effective May 15, 1989 between MLB Investments, Ltd., and Latoka.(6)
10.1(x)	Letter Agreement dated September 20, 1989 between MLB Investments, Ltd., and Latoka.(6)
10.1(y)	Letter Agreement dated May 17, 1989 between the Company and SOCO extending option period.(7)
10.1(z)	Purchase and Sale Agreement, dated as of June 20, 1991, between the Company and Taconic.(7)
10.1(aa)	Amended and Restated Stock Purchase Agreement, dated as of November 20, 1990, between Sparton Corporation, SOCO and the Company.(7)
10.1(bb)	Purchase and Sale Agreement, dated as of March 14, 1991, between Michigan Oil Company and Albercan Oil Corporation ("Albercan").(7)
10.1(cc)	Share Purchase and Sale Agreement, dated March 14, 1991, among SOCO, the Company and Albercan.(7)

10.1(dd)	Purchase and Sale Agreement, date March 15, 1993 between the Company and Valley Resources, Inc.(8)
10.1(ee)	Purchase and Sale Agreement, dated March 15, 1993 between the Company and Valley Oil and Gas, a Partnership.(8)
10.1(ff)	Loan Agreement dated May 25, 1993 between the Company and Bank One, Texas, N.A.(9)
10.1(gg)	Amendment dated August 8, 1993 to Loan Agreement dated May 25, 1993 between the Company and Bank One, Texas, N.A.(9)
10.1(hh)	Letter of Intent, dated September 20, 1993 between the Company and Mark Resources Corporation.(9)
10.1(ii)	Acquisition Agreement, dated October 16, 1993, among the Company, the Shareholders and Option Holders named therein, and Mark Resources Corporation.(10)
10.1(jj)	Form of Consulting Agreement between the Company and Peter M. Mark.(11)
10.1(kk)	Amendment dated November 12, 1993 to Loan Agreement dated May 25, 1993 between the Company and Bank One, Texas, N.A.(11)
10.1(ll)	Form of Directors Indemnification Agreement (12)
10.1(mm)	Acquisition Agreement dated as of February 8, 1994 among the Company, the Shareholders named therein and Grand Banks Energy Company (13)
10.1(nn)	Amendment dated March 7, 1994 to Loan May 25, 1993 Agreement dated between the Company and Bank One, Texas, N.A. (14)
10.1(oo)	1994 Outside Directors Stock Option Plan. (15)
10.1(pp)	1994 Stock Option Plan. (15)
10.1(qq)	Amended and Restated Revolving Credit and Term Loan Agreement dated July 6, 1994 between Lomak Petroleum, Inc. and Bank One, Texas N.A. and Texas Commerce Bank National Association. (16)
10.1(rr)	First Amendment to Amended and Restated Revolving Credit and Term Loan Agreement dated October 20, 1994 between Lomak Petroleum, Inc. and Bank One Texas, N.A. and Texas Commerce Bank National Association. (16)
10.1(ss)	Agreement and Plan of Merger dated as of October 28, 1994 between Registrant and Red Acquisition Corp. and Red Eagle Resources Corporation. (16)
10.1(tt)	Second Amendment to Amended and Restated Revolving Credit and Term Loan Agreement dated December 30, 1994 between Lomak Petroleum, Inc. and Bank One Texas, N.A. and Texas Commerce Bank National Association. (17)
10.1(uu)	Third Amendment to Amended and Restated Revolving Credit and Term Loan Agreement dated January 25, 1995 between Lomak Petroleum, Inc. and Bank One Texas, N.A. and Texas Commerce Bank National Association. (17)

10.1(vv)	Second Amended and Restated Revolving Credit and Term Loan Agreement dated December 20, 1995 between Lomak Petroleum, Inc., Lomak Operating Company, Lomak Production Company, Lomak Resources Company and Red Eagle Resources Corporation; Bank One, Texas N.A., Texas Commerce Bank National Association, Nationsbank of Texas, N.A. and PNC Bank, National Association.
11.1*	Computation of earnings per common and common equivalent shares.
22*	Subsidiaries of the Registrant.
23.1*	Consent of Independent Public Accountants.
27*	Financial Data Schedule.

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(1) Previously filed as Exhibit to Company's Registration Statement, Registration Statement No. 33-31558.
(2) Incorporated by reference to the Company's Form 8-K dated May 31, 1990.
(3) Incorporated by reference to the Company's Form 8-K dated March 15, 1990.
(4) Previously filed as exhibit to Xenda Corporation Form S-4 filed July 26, 1988, as amended, and incorporated herein by reference.
(5) Previously filed as exhibit to Xenda Corporation Form S-18 filed January 26, 1988, as amended, and incorporated herein by reference.
(6) Previously filed as exhibit to Latoka, Inc. Form 10-Q for the quarter ended September 30, 1989, and incorporated herein by reference.
(7) Incorporated by reference to the Company's Form 8-K dated August 5, 1991.
(8) Incorporated by reference to the Company's Form 8-K dated April 26, 1993 as amended by Form 8 dated June 23, 1993.
(9) Incorporated by reference to the Company's Registration Statement No. 33-70462 filed on October 18, 1993.
(10) Incorporated by reference to the Company's Pre-Effective Amendment No. 1 dated November 9, 1993, to the Company's Registration Statement No. 33-70462.
(11) Incorporated by reference to the Company's Post-Effective Amendment No. 1 dated December 10, 1993, to the Company's Registration Statement No. 33-70462.
(12) Incorporated by reference to the Company's Post-Effective Amendment No. 2 dated January 27, 1994.
(13) Incorporated by reference to the Company's Form 8-K dated February 11, 1994.
(14) Incorporated be reference to the Company's Form 10K for the year ended December 31, 1993, and incorporated herein by reference.
(15) Incorporated by reference to the Company's Post-Effective Amendment No. 4 dated May 3, 1994.
(16) Incorporated by reference to the Company's Form S-4 dated December 13, 1994
(17) Incorporated be reference to the Company's Form 10K for the year ended December 31, 1994, and incorporated herein by reference.

* Filed herewith.

EXHIBIT 11.1

LOMAK PETROLEUM, INC.

COMPUTATION OF EARNINGS PER COMMON
AND COMMON EQUIVALENT SHARES

	Year Ended December 31,		
	1994	1995	1996
	(In thousands, except per share data)		
Average shares outstanding	8,902	11,674	14,334
Net effect of conversion of warrants and stock options	149	167	478
Total primary and fully diluted shares	9,051	11,841	14,812
Net income	$ 2,619	$ 4,390	$ 12,615
Less preferred stock dividends	(375)	(731)	(2,454)
Net income applicable to common shares	$ 2,244	$ 3,659	$ 10,161
Earnings per common share	$ 0.25	$ 0.31	$ 0.69

EXHIBIT 22

LOMAK PETROLEUM, INC.

SUBSIDIARIES OF REGISTRANT

Name	Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Lomak Operating Company	Ohio	100%
Lomak Production Company	Delaware	100%
Buffalo Oilfield Services, Inc.	Ohio	100%
Lomak Energy Services Company	Delaware	100%
Lomak Resources Company	Delaware	100%
Eastern Petroleum Company	Ohio	100%

EXHIBIT 23.1

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report dated February 14, 1997, included in this Form 10-K, into the Company's previously filed Registration Statements on Form S-8 File No. 33-66322, Form S-3 File No. 33-64303 and on Form S-3 File No. 333-20257.

Arthur Andersen LLP

Cleveland, Ohio
March 21, 1997

5
1,000
DOLLARS

YEAR
DEC-31-1996
JAN-01-1996
DEC-31-1996
1
8,625
7,658
18,121
0
799
35,203
303,658
(58,099)
282,547
22,307
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148
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1,150
116,231
282,547
68,054
91,238
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38,033
33,756
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7,487
19,449
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12,615
0.69
0.69