FORM 424B1

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FILER

POGO PRODUCING CO

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SIC: **1311** Crude petroleum & natural gas

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SEC FILE NO. 33-52425
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PROSPECTUS

$75,000,000
POGO PRODUCING COMPANY

5 1/2% CONVERTIBLE SUBORDINATED NOTES DUE 2004

The 5 1/2% Convertible Subordinated Notes due 2004 (the 'Notes') are convertible at any time prior to maturity, unless previously redeemed, into shares of common stock, par value $1 per share (the 'Common Stock') of Pogo Producing Company (the 'Company'), at a conversion price of $22.188 per share, subject to adjustment upon the occurrence of certain events. On March 16, 1994, the closing sale price of the Common Stock on the New York Stock Exchange was $17 3/4 per share. The Common Stock is traded under the symbol 'PPP.'

Interest on the Notes is payable semi-annually on March 15 and September 15 of each year, commencing September 15, 1994. The Notes will mature on March 15, 2004 unless earlier redeemed or converted. The Notes will be redeemable at the option of the Company, in whole or in part, at any time on or after March 15, 1998, at the redemption prices set forth herein plus accrued and unpaid interest to the date of redemption. No sinking fund is provided for the Notes. The Notes are redeemable at the option of the holder, upon the occurrence of a Repurchase Event (as defined herein), at 100% of the principal amount thereof, plus accrued interest. See 'Description of the Notes.'

The Notes will be unsecured obligations of the Company, will be subordinated in right of payment to all existing and future Senior Indebtedness (as defined herein) of the Company, and will be effectively subordinated to all indebtedness and liabilities of subsidiaries of the Company. The Indenture with respect to the Notes will not restrict the incurrence of any other indebtedness or liabilities by the Company or its subsidiaries. See 'Description of the Notes.'

SEE 'INVESTMENT CONSIDERATIONS' FOR A DISCUSSION OF CERTAIN FACTORS THAT SHOULD BE CONSIDERED IN EVALUATING AN INVESTMENT IN THE NOTES.

THESE SECURITIES HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE SECURITIES AND EXCHANGE COMMISSION OR ANY STATE SECURITIES COMMISSION NOR HAS THE SECURITIES AND EXCHANGE COMMISSION OR ANY STATE SECURITIES COMMISSION PASSED UPON THE ACCURACY OR ADEQUACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

<TABLE>
<CAPTION>

<S>	PRICE TO PUBLIC (1) <C>	UNDERWRITING DISCOUNT(2) <C>	PROCEEDS TO COMPANY(1)(3) <C>
Per Note----------------------------------	100%	2.5%	97.5%
Total(4)----------------------------------	$75,000,000	$1,875,000	$73,125,000

(1) Plus accrued interest, if any, from March 23, 1994.

(2) The Company has agreed to indemnify the several Underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended. See 'Underwriting.'

(3) Before deducting expenses payable by the Company estimated at $350,000.

(4) The Company has granted the Underwriters a 30-day option to purchase up to an additional $11,250,000 principal amount of Notes on the same terms set forth above to cover over-allotments, if any. If the Underwriters exercise such option in full, the Price to Public, Underwriting Discount and Proceeds to Company would be $86,250,000, $2,156,250 and $84,093,750, respectively. See 'Underwriting.'

</TABLE>

The Notes are being offered by the several Underwriters, subject to prior sale, when, as and if issued to and accepted by the Underwriters, and certain other conditions. The Underwriters reserve the right to withdraw, cancel or modify such offer and to reject orders in whole or in part. It is expected that delivery of the Notes will be made in New York, New York, on or about March 23, 1994.

MERRILL LYNCH & CO.

GOLDMAN, SACHS & CO.

PAINEWEBBER INCORPORATED

The date of this Prospectus is March 16, 1994.

AVAILABLE INFORMATION

The Company is subject to the informational requirements of the Securities Exchange Act of 1934, as amended (the 'Exchange Act'), and, in accordance therewith, files reports, proxy statements and other information with the Securities and Exchange Commission (the 'Commission'). Such reports, proxy statements and other information filed by the Company with the Commission may be inspected and copied at the Public Reference Section of the Commission at Room 1024, 450 Fifth Street, N.W., Judiciary Plaza, Washington, D.C. 20549, and at the following Regional Offices of the Commission: Chicago Regional Office, Northwestern Atrium Center, 500 West Madison Street, Suite 1400, Chicago, Illinois 60601-2511; and New York Regional Office, Seven World Trade Center, New York, New York 10048. Copies of such material may also be obtained from the Public Reference Section of the Commission at its principal office at Room 1024, Judiciary Plaza, 450 Fifth Street, N.W., Washington, D.C. 20549, at prescribed rates. The Company's registration statements, reports, proxy statements and other information may also be inspected at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005 and the Pacific Stock Exchange, 301 Pine Street, San Francisco, California 94104.

This Prospectus, which constitutes a part of a registration statement on Form S-3 (the 'Registration Statement') filed by the Company with the Commission under the Securities Act of 1933, as amended (the 'Securities Act'), omits certain of the information set forth in the Registration Statement. Reference is hereby made to the Registration Statement and to the exhibits thereto for further information with respect to the Company and the securities offered hereby. Statements contained herein concerning the provisions of such documents are necessarily summaries of such documents, and each such statement is qualified in its entirety by reference to the copy of the applicable document filed with the Commission. Copies of the Registration Statement and the exhibits thereto are on file at the offices of the Commission and may be obtained upon payment of the fee prescribed by the Commission, or may be examined without charge at the public reference facilities of the Commission described above.

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

The Company's Annual Report on Form 10-K for the year ended December 31, 1993 (the 'Annual Report') is incorporated herein by reference.

All documents filed by the Company pursuant to Section 13(a), 13(c), 14 or 15(d) of the Exchange Act subsequent to the date of this Prospectus and prior to the termination of the offering of the Notes hereunder (the 'Offering') shall be deemed to be incorporated by reference in this Prospectus and to be part hereof from the date of filing of such documents. Any statement contained in a document incorporated or deemed to be incorporated by reference shall be deemed to be modified or superseded for purposes of this Prospectus to the extent that a statement contained herein or in any other subsequently filed incorporated document or in any accompanying prospectus supplement modifies or supersedes such statement. Any such statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Prospectus.

Copies of all documents incorporated herein by reference other than exhibits to such documents (unless such exhibits are specifically incorporated by reference) will be provided without charge to each person who receives a copy of this Prospectus upon written or oral request to Gerald A. Morton, Associate General Counsel, Pogo Producing Company, P.O. Box 2504, Houston, Texas 77252-2504 (telephone: (713) 297-5017).

IN CONNECTION WITH THE OFFERING, THE UNDERWRITERS MAY OVER-ALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF THE NOTES OFFERED HEREBY OR THE COMMON STOCK, OR EACH OF THEM, AT A LEVEL ABOVE THAT WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH TRANSACTIONS MAY BE EFFECTED ON THE NEW YORK STOCK EXCHANGE, THE PACIFIC STOCK EXCHANGE, IN THE OVER-THE-COUNTER MARKET OR OTHERWISE. SUCH STABILIZING, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

PROSPECTUS SUMMARY

THIS SUMMARY IS QUALIFIED IN ITS ENTIRETY BY, AND SHOULD BE READ IN CONJUNCTION WITH, THE MORE DETAILED INFORMATION AND FINANCIAL STATEMENTS APPEARING ELSEWHERE OR INCORPORATED BY REFERENCE IN THIS PROSPECTUS. EXCEPT AS OTHERWISE SPECIFIED, THE INFORMATION IN THIS PROSPECTUS ASSUMES NO EXERCISE OF THE UNDERWRITERS' OVER-ALLOTMENT OPTION. SEE 'GLOSSARY OF OIL AND GAS TERMS' FOR DEFINITIONS OF CERTAIN TERMS USED IN THIS PROSPECTUS. INVESTORS SHOULD CAREFULLY CONSIDER THE INFORMATION SET FORTH UNDER THE CAPTION 'INVESTMENT CONSIDERATIONS.'

THE COMPANY

Pogo Producing Company is an independent oil and gas exploration and production company, based in Houston, Texas, with an extensive Gulf of Mexico reserve and acreage position. The Company is also active in the Permian Basin of New Mexico, and has a 31.7% working interest in a 2.6 million acre concession license in the Gulf of Thailand. At December 31, 1993, the Company had interests in 597 gross oil and gas wells. At January 1, 1994, the Company's proved reserves, as estimated by Ryder Scott Company Petroleum Engineers ('Ryder Scott'), totaled 28.3 MMBbls of oil, condensate and natural gas liquids and 232.9 Bcf of natural gas. See 'Business and Properties -- Reserves.'

The Company's business strategy is to maximize profitability and shareholder value by (i) steadily increasing hydrocarbon production levels, leading to increased revenues, cash flow, and earnings, (ii) expanding its hydrocarbon reserves base, (iii) maintaining appropriate levels of debt and interest expense, and controlling overhead and operating costs, and (iv) expanding exploration and production activities into new and promising geographic areas consistent with Company expertise.

To implement its business strategy, the Company currently is focusing substantial attention and resources in the following geographic areas:

THE GULF OF MEXICO. Approximately 68% of the Company's proved oil and gas reserves are located in the Gulf of Mexico. Most of these proved reserves are concentrated in five significant producing areas, including eight fields in the Eugene Island area located off the Louisiana coast. This concentration allows the Company to closely manage costs and to develop detailed geologic and other information relating to its properties. The Company believes that the Gulf of Mexico will continue to provide the Company with substantial opportunities to expand its hydrocarbon reserves and to increase its deliverability. The Company is utilizing its extensive inventory of 3-D seismic data (covering 24 of the Company's lease blocks and 81 other lease blocks in the Gulf of Mexico) and conventional 2-D seismic data (approximately one-half million miles of which are located in the Gulf of Mexico) to locate low risk exploration and development projects. In addition to conventional vertical and deviated drilling, the Company will also utilize horizontal drilling (the Company participated in seven horizontal wells in 1993 alone) to accelerate development of its offshore projects. To expand its reserves base and increase its deliverability, the Company will rely on its 24 years of experience in the Gulf of Mexico, where it holds an extensive acreage position. The Company currently holds interests in 76 offshore blocks, and will continue to evaluate and acquire additional acreage with significant exploration and development potential. The Company, which historically has not operated a substantial percentage of its offshore properties, has assumed the operation of certain of its properties where the Company believes that its technical expertise and ability to control overhead and operating costs will enhance its economic interests. In its role as operator, the Company recently used a 3-D seismic survey to pinpoint the location of potentially recoverable shallow natural gas reserves on a portion of its Eugene Island Block 295 field, and horizontal drilling technology, including five horizontal wells, to optimize the exploitation of the field's shallow natural gas reserves.

NEW MEXICO. The Company continues to enjoy substantial success in its efforts to increase liquids production from its properties in southeastern New Mexico. The Company is currently one of the most active companies drilling for oil and gas in the southeastern New Mexico portion of the Permian Basin, where, from late 1989 through the end of 1993, the Company and its partners have drilled and completed as productive 151 consecutive wells, including 58 wells during 1993 alone. The Company has achieved rapid cost recovery with respect to its New Mexico wells drilled to date because of relatively low capital costs and high initial rates of production. Due to its historical drilling success, its current undeveloped acreage position and its commitment to additional drilling, the Company expects its New Mexico operations to continue to be a source of significant reserves and of liquids production. The Company's primary drilling objective in southeastern New Mexico is the Brushy Canyon (Delaware) formation, which produces oil at depths of approximately 6,000 to 9,000 feet. The Company's net revenue interest portion of daily liquid hydrocarbon production in New Mexico averaged approximately 3,700 Bbls during 1993, compared to approximately 2,050 Bbls per day during 1992, an increase of approximately 80%.

THE GULF OF THAILAND. The Company has conducted international exploration activities since the late 1970's in numerous oil and gas provinces in various parts of the world. The Company pursues a strategy of evaluating potentially high return prospects in areas of the world with a stable political and financial climate, such as certain European and ASEAN ('Association of Southeast Asian Nations') countries. Consistent with this strategy, in August 1991, the Company and its joint venture partners were awarded a license to explore for oil and gas on a 2.6 million acre concession, Block B8/32, in the Gulf of Thailand. The concession is located in a basin on trend with several oil and gas fields operated by Unocal Thailand Ltd. Through November 1993, Unocal Thailand Ltd. has reported cumulative production from more than 700 wells in these fields totaling approximately 2 trillion cubic feet of natural gas and 71 MMBbls of oil and condensate. Following an initial evaluation of the Thailand concession area, the Company and its joint venture partners drilled five exploratory wells on three separately identified seismic structures. The first well drilled, the Tantawan No. 1, successfully tested a large, complexly faulted, anticlinal structure with production tests from five intervals resulting in calculated cumulative flow rates of 6,260 Bbls of oil and condensate and 25,750 Mcf of natural gas per day. During 1993, the Company and its joint venture partners shot, processed and evaluated approximately 9,000 kilometers of new 3-D seismic data over and around the Tantawan No. 1 well. In late 1993, the Company drilled the Tantawan No. 2 and the Tantawan No. 3 exploratory wells on the Tantawan structure. The Tantawan No. 2 well successfully delineated a previously untested fault block to the east of the Tantawan No. 1 well with production tests from six intervals resulting in calculated cumulative flow rates of 70,300 Mcf of natural gas and 1,720 Bbls of condensate per day. The Tantawan No. 3 well successfully delineated a third untested fault block on the Tantawan structure located approximately two miles north of the Tantawan No. 1 and No. 2 wells. Production tests from this third Tantawan well were reported in January 1994, with production tests from five intervals resulting in calculated cumulative flow rates of 40,660 Mcf of natural gas and 8,684 Bbls of oil and condensate per day. As a result of its successful exploration drilling program, the Company's Thailand concession now accounts for approximately 14% of the Company's total estimated net proved reserves of natural gas, approximately 19% of the Company's total estimated net proved reserves of oil, condensate and natural gas liquids and approximately 16% of the Company's total net proved oil and gas equivalent reserves. During 1994, additional delineation wells on the Tantawan structure are planned. Based upon the results of such drilling, the Company and its partners will agree upon the type of development plan needed to commence production in this area. In addition, in late 1993, the Company and its joint venture partners began shooting and processing additional 3-D seismic data on a different portion of Block B8/32. Following evaluation of this seismic data, additional exploratory wells are expected to be drilled by the

Company and its joint venture partners on as yet untested seismic structures identified on Block B8/32.

While maintaining an active exploration and development program, the Company also continues to focus on its strategy of maintaining appropriate levels of debt and interest expense. The Company has reduced its total debt and production payment obligations from $472,400,000 as of January 1, 1988, to $134,539,000 as of December 31, 1993, a decrease of approximately 72%.

The reduction of total debt and production payment obligations has allowed the Company to devote increased amounts of its cash flow toward exploration and development of its premium property base. The Company's drilling successes have resulted in increased equivalent oil and gas production during 1992 and 1993, as compared to the prior five years, while simultaneously expanding its reserves base. In 1992 and 1993, the Company replaced 143% and 204%, respectively, of its total production of proved hydrocarbon reserves. The Company believes that the increased liquidity and increased average maturity of its outstanding indebtedness resulting from the Offering will provide the Company with additional financial flexibility to pursue its business strategy and maximize shareholder value. For 1994, the Company's Board of Directors has authorized capital and exploration expenditures of $75,000,000, approximately equal to the Company's capital and exploration expenditures of approximately $74,600,000 in 1993. See 'The Company,' 'Management's Discussion and Analysis of Financial Condition and Results of Operations' and 'Business and Properties.'

<TABLE>

THE OFFERING

<S>	<C>
Notes Offered	$75,000,000 principal amount of 5 1/2% Convertible Subordinated Notes due 2004 (excluding $11,250,000 aggregate principal amount of Notes subject to the Underwriters' over-allotment option).
Interest Payment Dates	March 15 and September 15 of each year, commencing September 15, 1994.
Conversion Rights	Convertible into Common Stock of the Company at the option of the holder at any time before maturity (unless earlier redeemed) at $22.188 per share (equivalent to a conversion rate of approximately 45.069 shares per $1,000 principal amount of Notes), subject to adjustment upon the occurrence of certain events. See 'Description of the Notes -- Conversion Rights.'

Ranking------------------------------	The Notes will be unsecured and subordinated to all existing and future Senior Indebtedness of the Company and effectively subordinated to all indebtedness and other liabilities of subsidiaries of the Company. The Indenture relating to the Notes contains no limitation on the incurrence of indebtedness or other liabilities by the Company or its subsidiaries. The Notes will rank PARI PASSU with the Company's one other issue of convertible subordinated indebtedness that will remain outstanding after application of the proceeds of the Offering. See 'Use of Proceeds,' 'Capitalization' and 'Description of the Notes -- Subordination.'

Optional Redemption------------------	The Notes are redeemable at the option of the Company, in whole or in part, at any time on or after March 15, 1998, at the redemption prices set forth herein plus accrued interest to the date of redemption. Accrued and unpaid interest to the redemption date shall be payable with respect to Notes that are converted after a notice of redemption has been mailed and prior to the redemption date. See 'Description of the Notes -- Redemption at Option of Company.'
Repurchase at Holder's Option-----------------------------	Upon the occurrence of a Repurchase Event, each holder of Notes shall have the right, at the holder's option, to require the Company to repurchase such Notes at 100% of their principal amount, plus accrued interest. The term Repurchase Event is limited to certain transactions involving a Change of Control (as defined herein) in which (i) the market price of the Common Stock at the time of, and the aggregate fair market value of the consideration received in, such transaction is less than 105% of the conversion price and (ii) the Notes become convertible into securities other than publicly traded common stock. See 'Description of the Notes -- Certain Rights to Require Repurchase of Notes.'
Use of Proceeds----------------------	The net proceeds from the Offering will be used to repay certain indebtedness of the Company. See 'Use of Proceeds.'
Absence of Public Market-------------	The Notes are a new issue for which there is currently no public market. The Company does not intend to apply for listing of the Notes on a securities exchange or for quotation on the NASDAQ National Market. If an active public market does not develop, the market price and liquidity of the Notes may be adversely affected. See 'Investment Considerations -- Absence of Public Market' and 'Underwriting.'

</TABLE>
For additional information concerning the Notes, see 'Description of the Notes.'

SUMMARY FINANCIAL AND OPERATING DATA

The Summary Financial and Operating Data presented below for, and as of the end of, each of the years in the five-year period ended December 31, 1993, are derived from the consolidated financial statements of the Company and its subsidiaries, which have been audited by independent public accountants. The information presented under the captions 'Production (Sales) Data,' 'Selected Ratios' and 'Reserve Data' is unaudited. This data should be read in conjunction with the consolidated financial statements and related notes thereto and 'Management's Discussion and Analysis of Financial Condition and Results of Operations' included elsewhere in this Prospectus.

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	YEAR ENDED DECEMBER 31,				
	1993	1992	1991	1990	1989
	(EXPRESSED IN THOUSANDS, EXCEPT PER SHARE AND UNIT AMOUNTS, EXCEPT AS NOTED)				
<S>	<C>	<C>	<C>	<C>	<C>
INCOME STATEMENT DATA:					
Total revenues-----------------------	$ 139,554	$ 140,830	$ 124,469	$ 154,820(a)	$ 120,947
Operating income---------------------	50,533	47,141	37,239	72,940(a)	37,375
Net interest expense-----------------	10,505	18,645	24,309	30,700	36,352
Net income---------------------------	25,061	18,495	11,658	44,036(a)	2,638
Primary and fully diluted earnings					

per share	$ 0.76	$ 0.66	$ 0.42	$ 1.69(a)	$ 0.11
OTHER FINANCIAL DATA:					
EBITDA(b)	$ 96,381	$ 99,339	$ 81,637	$ 116,760(a)	$ 87,384
Capital and exploration expenditures (excluding capitalized interest)	74,600	41,300	53,100	39,500	25,800

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	YEAR ENDED DECEMBER 31,				
	1993	1992	1991	1990	1989
	(EXPRESSED IN THOUSANDS, EXCEPT PER SHARE AND UNIT AMOUNTS)				
SELECTED RATIOS:					
EBITDA/Net interest expense	9.2	5.3	3.4	3.8	2.4
Ratio of earnings to fixed charges(c)	4.5	2.5	1.6	2.3	1.0
Long-term obligations/Total proved reserves (BOE)(d)	$ 1.95	$ 2.52	$ 4.22	$ 4.70	$ 5.49

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	AS OF DECEMBER 31, 1993	
	ACTUAL	AS ADJUSTED(E)
	(EXPRESSED IN THOUSANDS)	
BALANCE SHEET DATA:		
Total assets	$ 239,774	$ 242,302
Long-term obligations, including current portion	134,539	137,539
Shareholders' equity	33,803	33,496

(a) In late 1990, the Company entered into a settlement agreement with the Internal Revenue Service for a refund of $8,607,000 in taxes for taxable years 1976 through 1985 which, together with accrued interest of $20,395,000, resulted in a refund receivable of $29,002,000 through December 31, 1990. The refund and interest income, together with the reversal of previously accrued interest expense of $2,104,000, contributed $22,499,000 to total revenues and $23,456,000 or $0.90 per share to earnings in 1990. The refund along with additional accrued interest was received by the Company on May 31, 1991.

(b) EBITDA represents income from continuing operations before provision for income taxes, interest expense, interest income, interest capitalized, depreciation and amortization, and dry hole and impairment costs. EBITDA is presented as a measure of the Company's debt service ability, and not as an alternative to (i) operating income (as determined in accordance with generally accepted accounting principles) as an indicator of the Company's operating performance, or (ii) cash flows from operating activities (as determined in accordance with generally accepted accounting principles) as a measure of liquidity.

(c) Income before taxes and extraordinary item plus fixed charges (net of capitalized interest) divided by fixed charges. Fixed charges are defined as interest expense plus the portion of rental expense representing interest.

(d) Long-term obligations include long-term debt (excluding current maturities) and the non-current portion of the Eugene Island Block 330 production payment obligation until such obligation was satisfied in 1993. Total proved reserves are expressed on an energy equivalent basis. BOE means Bbls of oil on an energy equivalent basis. See 'Glossary of Oil and Gas Terms.'

(e) Adjusted to give effect to the Offering and the use of proceeds therefrom.
</TABLE>

<TABLE>
SUMMARY FINANCIAL AND OPERATING DATA -- (CONTINUED)

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	YEAR ENDED DECEMBER 31,				
	1993	1992	1991	1990	1989
	(EXPRESSED IN THOUSANDS, EXCEPT PER UNIT AMOUNTS)				
PRODUCTION (SALES) DATA:					
Net daily average and weighted average price:					
Natural gas:					
Mcf per day	91,700	105,200	104,200	107,300	111,300
Price per Mcf	$ 1.98	$ 1.75	$ 1.66	$ 1.89	$ 1.88

Crude oil-condensate:					
Bbls per day	9,851	8,699	7,108	6,209	6,013
Price per Bbl	$ 17.81	$ 20.17	$ 20.98	$ 23.84	$ 18.86
Natural gas liquids:					
Bbls per day	1,678	1,181	663	697	948
Price per Bbl	$ 11.90	$ 13.50	$ 14.21	$ 13.75	$ 10.16
RESERVE DATA:					
Estimated proved reserves					
Crude oil, condensate and natural gas liquids (MBbls)	28,268	22,556	18,818	19,090	17,658
Natural gas (MMcf)	232,866	207,068	202,735	217,500	234,112
Natural gas equivalent (MMcfe)(f)	402,474	342,404	315,643	332,040	340,060
Estimated future net revenues before income taxes, discounted at 10%	$ 403,840	$ 405,101	$ 349,754	$ 525,173	$ 441,917

(f) MMcfe means MMcf on an energy equivalent basis.
</TABLE>

INVESTMENT CONSIDERATIONS

Prospective purchasers of the Notes offered hereby should carefully consider the following factors, as well as the information contained elsewhere in this Prospectus, before purchasing the Notes.

VOLATILITY OF OIL AND GAS MARKETS

The Company's profitability and cash flow are highly dependent upon the prices of oil and natural gas, which historically have been seasonal, cyclical and volatile. In general, prices of oil and gas are dependent upon numerous factors beyond the control of the Company, including various weather, economic, political and regulatory conditions. In the past, when natural gas prices in the United States were lower than they are currently, the Company at times elected to curtail certain quantities of its production capacity. Should natural gas prices fall in the future, the Company may again elect to curtail certain quantities of its natural gas production capacity. Any significant decline in oil or gas prices could have a material adverse effect on the Company's operations and financial condition and could, under certain circumstances, result in a reduction in funds available under the Credit Agreement (as defined herein) and the Company's ability to meet its debt service obligations. Because it is impossible to predict future oil and gas price movements with any certainty, the Company from time to time enters into contracts on a portion of its production to hedge against the volatility in oil and gas prices. Such hedging transactions historically have not exceeded 50% of the Company's total oil and gas production on an energy equivalent basis for any given period. While intended to limit the negative effect of price declines, such transactions could effectively limit the Company's participation in price increases for the covered period, which price increases could be significant. See ' -- Subordination of Notes; Leverage and Debt Service' and 'Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources.'

ESTIMATES OF RESERVES AND FUTURE NET REVENUES

There are numerous uncertainties inherent in estimating the quantity of proved oil and gas reserves and in projecting the future rates of production and timing of development expenditures. Engineering of oil and gas reserves is a subjective process of estimating underground accumulations of oil and gas that cannot be measured precisely, and estimates of other engineers might differ materially from those prepared by Ryder Scott, the independent engineering firm retained by the Company. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimates may justify revisions of such estimates. Accordingly, reserve estimates are generally different from the quantities of oil and gas that are ultimately recovered. In addition, estimates of the Company's future net revenues from proved reserves and the present value thereof are based on certain assumptions regarding future oil and gas prices, production levels and operating and development costs that may not prove to be correct. Any significant variance in these assumptions could materially affect the estimated quantity of reserves and future net revenues therefrom set forth in this Prospectus. See 'Business and Properties -- Reserves.'

OPERATING AND UNINSURED RISKS

The Company's operations are subject to risks inherent in the exploration for and production of oil and natural gas, such as blowouts, cratering, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pollution and other environmental risks. Offshore oil and gas operations are subject to the additional hazards of marine operations, such as capsizing, collision and adverse weather and sea conditions. These hazards could result in substantial losses to the Company due to injury or loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. The Company carries insurance which it believes is in

accordance with customary industry practices, but is not fully insured against all risks incident to its business.

Drilling activities are subject to numerous risks, including the risk that no commercially productive hydrocarbon reserves will be encountered. The cost of drilling, completing and operating wells is often uncertain. The Company's drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including weather conditions, compliance with governmental requirements and shortages or delays in the delivery of equipment. The availability of a ready market for the Company's natural gas production depends on a number of factors, including the demand for and supply of natural gas, the proximity of natural gas reserves to pipelines, the capacity of such pipelines and government regulations.

SUBORDINATION OF NOTES; LEVERAGE AND DEBT SERVICE

The Notes will be subordinated obligations of the Company and, as such, will be subordinated to all of the Company's existing and future Senior Indebtedness. After giving effect to the Offering and the application of proceeds therefrom, approximately $19,000,000 principal amount of Senior Indebtedness will be outstanding. The Company may incur additional Senior Indebtedness from time to time in the future under the Credit Agreement or otherwise, and the Indenture relating to the Notes will not restrict the incurrence of any other indebtedness or liabilities by the Company or its subsidiaries. Upon any distribution of assets, liquidation, dissolution, reorganization or any similar proceeding by or relating to the Company, the holders of Senior Indebtedness of the Company would be entitled to receive payment in full before the holders of the Notes would be entitled to receive any payment. The terms and conditions of the subordination provisions pertinent to the Notes are described in more detail in 'Description of the Notes -- Subordination.'

Further, the Notes will be effectively subordinated to claims of holders of any preferred stock and claims of creditors (other than the Company) of the Company's subsidiaries, including trade creditors, secured creditors, taxing authorities, creditors holding guarantees, and tort claimants. In the event of a liquidation, reorganization, or similar proceeding relating to a subsidiary, these persons generally would have priority as to the assets of such subsidiary over the claims and equity interest of the Company and, thereby indirectly, holders of the Company's indebtedness, including the Notes. As of December 31, 1993, there were no material outstanding liabilities of subsidiaries of the Company, but such liabilities may be incurred in the future.

On a pro forma basis after giving effect to the Offering, as of December 31, 1993, the Company's long-term debt (including the current portion) would have been $137,539,000 and shareholders' equity would have been $33,496,000, and thus the Company may continue to be considered highly leveraged. See 'Capitalization.' The Company believes that its cash flow from operations, together with the proceeds from the Offering, the funds available under the Credit Agreement and its other sources of liquidity, will be adequate to meet its anticipated requirements for working capital, capital expenditures, interest payments and scheduled principal payments. See 'Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources.' However, the Company's ability to meet its debt service obligations will be dependent upon its future performance, which, in turn, will be subject to general economic conditions and to financial, business and other factors affecting the operations of the Company, many of which are beyond its control. Upon the occurrence of a Repurchase Event, the Company may be required, subject to certain conditions, to purchase some or all of the outstanding Notes at a price equal to 100% of the principal amount thereof, plus accrued interest. There can be no assurance that the Company would have sufficient financial resources at the time of such required purchase to enable it to purchase such Notes. See 'Description of the Notes -- Certain Rights to Require Repurchase of Notes.'

GOVERNMENT REGULATION AND ENVIRONMENTAL RISKS

The Company's business is subject to certain laws and regulations relating to taxation, exploration for and development and production of oil and gas, and environmental and safety matters in both the United States and the foreign countries in which the Company or any of its subsidiaries operates or owns property. Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of oil and gas, including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these statutes and regulations, as well as other regulations that could be promulgated by the jurisdictions in which the Company has production, could be to limit allowable production from the Company's properties and thereby to limit its revenues.

The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to the government and third parties and may require the Company to incur costs to remedy the discharge. Oil or natural gas may be discharged in many ways, including from a well or drilling equipment at a drill site, leakage from storage tanks, pipelines or other gathering and transportation facilities and discharges resulting from damage to oil or natural gas wells related to accidents during normal operations, as well as blowouts, cratering and explosions. Discharged oil and gas may migrate through soil to water supplies or adjoining properties, giving rise to additional liabilities. A variety of laws and regulations govern the environmental aspects of oil and gas production, transportation and processing and may, in addition to other laws, impose liability in the event of discharges (whether or not accidental), for failure to notify the proper authorities of a discharge and for other failures to comply with those laws. For example, the Oil Pollution Act of 1990 (the 'OPA') imposes a variety of regulations related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. On August 25, 1993, the Department of the Interior's Mineral Management Service (the 'MMS') published an advance notice of intention to adopt a rule under OPA requiring operators such as the Company to establish $150,000,000 in financial responsibility. The Company cannot predict the final form of the financial responsibility rule that will be adopted by the MMS, but such rule has the potential to result in the imposition of substantial additional annual costs on the Company or otherwise materially adversely affect the Company. Environmental laws may also affect the costs of the Company's acquisitions of oil and gas properties. The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. Nevertheless, no assurance can be given that environmental laws will not, in the future, result in a curtailment of production or a material increase in the costs of production, development or exploration or otherwise adversely affect the Company's operations and financial condition. Pollution and similar environmental risks generally are not fully insurable.

RISKS OF FOREIGN OPERATIONS

Ownership of property interests and production operations in Thailand and other areas outside the United States are subject to the various risks inherent in foreign operations. These risks include, among others, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, insurrection and other political risks, risks of increases in taxes and governmental royalties, and renegotiation of contracts with governmental entities, as well as changes in laws and policies governing operations of foreign-based companies.

ABSENCE OF PUBLIC MARKET

The Notes are a new issue for which there is currently no public market. The Company does not intend to apply for listing of the Notes on any securities exchange or for quotation on NASDAQ. The Company has been advised by the Underwriters that, following the completion of the Offering, each of the Underwriters presently intends to make a market in the Notes, although the Underwriters are under no obligation to do so and may discontinue any market making at any time without notice. No assurance can be given regarding the liquidity of the trading market for the Notes or that an active trading market for the Notes will develop. If an active public market does not develop, the market price and liquidity of the Notes may be adversely affected. See "Underwriting."

THE COMPANY

GENERAL

The Company is an independent oil and gas exploration and production company, based in Houston, Texas, with an extensive Gulf of Mexico reserve and acreage position. The Company is also active in the Permian Basin of New Mexico, and has a 31.7% working interest in a 2.6 million acre concession license in the Gulf of Thailand. At December 31, 1993, the Company had interests in 597 gross oil and gas wells. At January 1, 1994, the Company's proved reserves, as estimated by Ryder Scott, totaled 28.3 MMBbls of oil, condensate and natural gas liquids and 232.9 Bcf of natural gas. See 'Business and Properties -- Reserves.'

BUSINESS STRATEGY

The Company's business strategy is to maximize profitability and shareholder value by (i) steadily increasing hydrocarbon production levels, leading to increased revenues, cash flow, and earnings, (ii) expanding its hydrocarbon reserves base, (iii) maintaining appropriate levels of debt and interest expense, and controlling overhead and operating costs, and (iv) expanding exploration and production activities into new and promising geographic areas consistent with Company expertise.

To implement its business strategy, the Company currently is focusing substantial attention and resources in the following geographic areas:

THE GULF OF MEXICO. Approximately 68% of the Company's proved oil and gas reserves are located in the Gulf of Mexico. Most of these proved reserves are concentrated in five significant producing areas, including eight fields in the Eugene Island area located off the Louisiana coast. This concentration allows the Company to closely manage costs and to develop detailed geologic and other information relating to its properties. The Company believes that the Gulf of Mexico will continue to provide the Company with substantial opportunities to expand its hydrocarbon reserves and to increase its deliverability. The Company is utilizing its extensive inventory of 3-D seismic data (covering 24 of the Company's lease blocks and 81 other lease blocks in the Gulf of Mexico) and conventional 2-D seismic data (approximately one-half million miles of which are located in the Gulf of Mexico) to locate low risk exploration and development projects. In addition to conventional vertical and deviated drilling, the Company will also utilize horizontal drilling (the Company participated in seven horizontal wells in 1993 alone) to accelerate development of its offshore projects. To expand its reserves base and increase its deliverability, the Company will rely on its 24 years of experience in the Gulf of Mexico, where it holds an extensive acreage position. The Company currently holds interests in 76 offshore blocks, and will continue to evaluate and acquire additional acreage with significant exploration and development potential. The Company, which historically has not operated a substantial percentage of its offshore properties, has assumed the operation of certain of its properties where the Company believes that its technical expertise and ability to control overhead and operating costs will enhance its economic interests. In its role as operator, the Company recently used a 3-D seismic survey to pinpoint the location of potentially recoverable shallow natural gas reserves on a portion of its Eugene Island Block 295 field, and horizontal drilling technology, including five horizontal wells, to optimize the exploitation of the field's shallow natural gas reserves.

NEW MEXICO. The Company continues to enjoy substantial success in its efforts to increase liquids production from its properties in southeastern New Mexico. The Company is currently one of the most active companies drilling for oil and gas in the southeastern New Mexico portion of the Permian Basin, where, from late 1989 through the end of 1993, the Company and its partners have drilled and completed as productive 151 consecutive wells, including 58 wells during 1993 alone. The Company has achieved rapid cost recovery with respect to its New Mexico wells drilled to date because of relatively low capital costs and high initial rates of production. Due to its historical drilling success, its current undeveloped acreage position and its significant budgetary commitment to additional drilling, the Company expects its New Mexico operations to continue to be a source of

significant reserves and of liquids production. The Company's primary drilling objective in southeastern New Mexico is the Brushy Canyon (Delaware) formation, which produces oil at depths of approximately 6,000 to 9,000 feet. The Company's net revenue interest portion of daily liquid hydrocarbon production in New Mexico averaged approximately 3,700 Bbls during 1993, compared to approximately 2,050 Bbls per day during 1992, an increase of approximately 80%.

THE GULF OF THAILAND. The Company has conducted international exploration activities since the late 1970's in numerous oil and gas provinces in various parts of the world. The Company pursues a strategy of evaluating potentially high return prospects in areas of the world with a stable political and financial climate, such as certain European and ASEAN countries. Consistent with this strategy, in August 1991, the Company and its joint venture partners were awarded a license to explore for oil and gas on a 2.6 million acre concession, Block B8/32, in the Gulf of Thailand. The concession is located in a basin on trend with several oil and gas fields operated by Unocal Thailand Ltd. Through November 1993, Unocal Thailand Ltd. has reported cumulative production from more than 700 wells in these fields totaling approximately 2 trillion cubic feet of natural gas and 71 MMBbls of oil and condensate. Following an initial evaluation of the Thailand concession area, the Company and its joint venture partners drilled five exploratory wells on three separately identified seismic structures. The first well drilled, the Tantawan No. 1, successfully tested a large, complexly faulted, anticlinal structure with production tests from five intervals resulting in calculated cumulative flow rates of 6,260 Bbls of oil and condensate and 25,750 Mcf of natural gas per day. During 1993, the Company and its joint venture partners shot, processed and evaluated approximately 9,000 kilometers of new 3-D seismic data over and around the Tantawan No. 1 well. In late 1993, the Company drilled the Tantawan No. 2 and the Tantawan No. 3 exploratory wells on the Tantawan structure. The Tantawan No. 2 well successfully delineated a previously untested fault block to the east of the Tantawan No. 1 well with production tests from six intervals resulting in calculated cumulative flow rates of 70,300 Mcf of natural gas and 1,720 Bbls of condensate per day. The Tantawan No. 3 well successfully delineated a third untested fault block on the Tantawan structure located approximately two miles north of the Tantawan No. 1 and No. 2 wells. Production tests from this third Tantawan well were reported in January 1994, with production tests from five intervals resulting in calculated cumulative flow rates of 40,660 Mcf of natural gas and 8,684 Bbls of oil and condensate per day. As a result of its successful exploration drilling program, the Company's Thailand concession now accounts for approximately 14% of the Company's total estimated net proved reserves of natural gas, approximately 19% of the Company's total estimated net proved reserves of oil, condensate and natural gas liquids and approximately 16% of the Company's total net proved oil and gas equivalent reserves. During 1994, additional delineation wells on the Tantawan structure are planned. Based upon the results of such drilling, the Company and its partners will agree upon the type of development plan needed to commence production in this area. In addition, in late 1993, the Company and its joint venture partners began shooting and processing additional 3-D seismic data on a different portion of Block B8/32. Following evaluation of this seismic data, additional exploratory wells are expected to be drilled by the Company and its joint venture partners on as yet untested seismic structures identified on Block B8/32.

While maintaining an active exploration and development program, the Company also continues to focus on its strategy of maintaining appropriate levels of debt and interest expense. The Company has reduced its total debt and production payment obligations from $472,400,000 as of January 1, 1988, to $134,539,000 as of December 31, 1993, a decrease of approximately 72%.

The reduction of total debt and production payment obligations has allowed the Company to devote increased amounts of its cash flow toward exploration and development of its premium property base. The Company's drilling successes have resulted in increased equivalent oil and gas production during 1992 and 1993, as compared to the prior five years, while simultaneously expanding its reserves base. In 1992 and 1993, the Company replaced 143% and 204%, respectively, of its total production of proved hydrocarbon reserves. The Company believes that the increased liquidity and increased average maturity of its outstanding indebtedness resulting from the Offering

will provide the Company with additional financial flexibility to pursue its business strategy and maximize shareholder value. For 1994, the Company's Board of Directors has authorized capital and exploration expenditures of $75,000,000, approximately equal to the Company's capital and exploration expenditures of approximately $74,600,000 in 1993. See 'The Company,' 'Management's Discussion and Analysis of Financial Condition and Results of Operations' and 'Business and Properties.'

The Company's principal executive offices are located at 5 Greenway Plaza, Suite 2700, Houston, Texas 77046. Its mailing address is P.O. Box 2504, Houston, Texas 77252-2504. The telephone number is (713) 297-5000.

USE OF PROCEEDS

The net proceeds to the Company from the sale of the Notes offered hereby are estimated to be approximately $72,775,000 (after deducting underwriting discounts and expenses of the Offering), or approximately $83,743,750 if the Underwriters' over-allotment option is exercised in full. The Company intends to apply approximately $24,500,000 (including prepayment premiums) of the net proceeds of the Offering to retire its 10.25% Convertible Subordinated Notes due 1999 (the '10.25% Notes'). The Company intends to apply the balance of the net proceeds to repay outstanding Senior Indebtedness under the Credit Agreement which, as of December 31, 1993, stood at $67,000,000 and bore interest at a floating rate that was approximately 5 3/8%. The Company may borrow additional amounts under the Credit Agreement or otherwise from time to time to fund capital expenditures or for other corporate purposes. The Company believes that the increased liquidity and increased average maturity of its outstanding indebtedness resulting from the Offering will provide the Company with additional financial flexibility to pursue its business strategy and maximize shareholder value. Pending application of the proceeds of the Offering as described above, a portion of such proceeds may be invested in short-term instruments. See 'The Company,' 'Capitalization,' and 'Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources.'

CAPITALIZATION

The following table sets forth the consolidated capitalization of the Company and its subsidiaries at December 31, 1993 (assuming net proceeds of $72,775,000, less the call premium on the early retirement of the 10.25% Notes and excess cash). The table has also been adjusted to reflect the issuance of the Notes offered hereby and the application of the net proceeds therefrom as described under 'Use of Proceeds.' This table should be read in conjunction with the Consolidated Financial Statements and related notes thereto included elsewhere in this Prospectus.

	DECEMBER 31, 1993	
	HISTORICAL	AS ADJUSTED
	(IN THOUSANDS)	
Long-term debt (including current portion):		
Credit Agreement indebtedness	$ 67,000	$ 19,000
5 1/2% Convertible Subordinated Notes due 2004	--	75,000
10.25% Convertible Subordinated Notes due 1999	24,000	--
8% Convertible Subordinated Debentures due 2005	43,539	43,539
Total long-term debt	134,539	137,539
Shareholders' equity:		
Preferred stock, $1 par value; 2,000,000 shares authorized; no shares issued and outstanding	--	--
Common stock, $1 par value; 43,333,333 shares authorized; 32,449,197 shares issued	32,449	32,449
Additional capital	125,919	125,919
Retained earnings (deficit)	(124,241)	(124,548)(a)
Treasury stock, at cost	(324)	(324)
Total shareholders' equity	33,803	33,496
Total capitalization	$ 168,342	$ 171,035

(a) Adjusted to reflect the after-tax effect of the early redemption of $16,000,000 of 10.25% Notes at 102.95% of their principal amount.

PRICE RANGE OF COMMON STOCK AND DIVIDENDS

The following table shows the range of low and high sales prices of the Company's Common Stock on the New York Stock Exchange composite tape where the Company's Common Stock trades under the symbol PPP. The Company's Common Stock is also listed on the Pacific Stock Exchange.

	LOW	HIGH
1992		
1st Quarter	$ 5 1/8	$ 6 1/2
2nd Quarter	5 1/8	6 3/8
3rd Quarter	5 1/2	10 3/8
4th Quarter	9 3/4	13 7/8
1993		
1st Quarter	$ 9 3/4	$ 17 1/4
2nd Quarter	16 1/8	21
3rd Quarter	13 5/8	19 1/8
4th Quarter	14 3/8	19 3/4
1994		
1st Quarter (through March 16, 1994)	$ 16 1/2	$ 21 5/8

The closing sale price of the Company's Common Stock on the New York Stock Exchange as of a recent date is set forth on the cover page of this Prospectus.

DIVIDEND POLICY

The Board of Directors of the Company has not declared cash dividends on the Company's Common Stock since the fourth quarter of 1986, and has no current plans to pay dividends. See 'Description of Capital Stock.'

Pursuant to various agreements under which the Company has borrowed funds, the Company may not, subject to certain exceptions, pay any dividends on its capital stock or make any other distributions on shares of its capital stock (other than dividends or distributions payable solely in shares of such capital stock) or acquire for value any shares of its capital stock if (after giving effect to the proposed payment, distribution, or acquisition) the aggregate amount of all such payments, distributions or acquisitions on and after a specified date would exceed an amount determined based on the consolidated income or cash flow of the Company and its consolidated subsidiaries from and after such date. As of December 31, 1993, $33,803,000 was available for dividends under the most restrictive of such limitations.

SELECTED FINANCIAL AND OPERATING DATA

The selected financial data presented below for, and as of the end of, each of the years in the five-year period ended December 31, 1993, are derived from the consolidated financial statements of the Company and its subsidiaries, which have been audited by independent public accountants. The information presented under the caption 'Production (Sales) Data' and 'Other Financial Data and Selected Ratios' is unaudited. This data should be read in conjunction with the consolidated financial statements and related notes thereto and 'Management's Discussion and Analysis of Financial Condition and Results of Operations' included elsewhere in this Prospectus.

<TABLE>
<CAPTION>

	YEAR ENDED DECEMBER 31,				
	1993	1992	1991	1990	1989
	(EXPRESSED IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)				
<S>	<C>	<C>	<C>	<C>	<C>
INCOME STATEMENT DATA:					
Revenues:					
Crude oil and condensate-----------	$ 64,042	$ 64,224	$ 54,420	$ 54,018	$ 41,396
Natural gas------------------------	66,173	67,366	63,225	74,111	76,287
Natural gas liquids----------------	7,288	5,833	3,442	3,496	3,516
Other, net-------------------------	(950)	1,705	3,338	794	(79)
Oil and gas revenues-------------	136,553	139,128	124,425	132,419	121,120
Interest on tax refunds------------	2,322(a)	--	--	22,499(a)	--
Gains (losses) on sales------------	679	1,702	44	(98)	(173)
Total------------------------	139,554	140,830	124,469	154,820	120,947
Operating costs and expenses:					
Lease operating--------------------	26,633	25,842	28,192	24,558	22,377
General and administrative---------	14,550	13,129	14,555	13,458	11,829
Exploration------------------------	2,455	3,102	2,408	2,029	2,078
Dry hole and impairment------------	4,690	9,314	4,554	5,501	8,443
Depreciation, depletion and amortization---------------------	40,693	42,302	37,521	36,334	38,845
Total------------------------	89,021	93,689	87,230	81,880	83,572
Operating income---------------------	50,533	47,141	37,239	72,940	37,375
Interest:					
Charges--------------------------	(10,956)	(19,036)	(24,946)	(31,441)	(37,458)
Income---------------------------	14	191	1,686	1,244	1,615
Capitalized----------------------	451	391	637	741	1,106
Income before income taxes and extraordinary item-----------------	40,042	28,687	14,616	43,484	2,638
Income tax (expense) benefit---------	(14,981)	(10,192)	(4,294)	552	--
Income before extraordinary item-----	25,061	18,495	10,322	44,036	2,638
Extraordinary gain on purchase of debt-------------------------------	--	--	1,336	--	--
Net income---------------------------	$ 25,061	$ 18,495	$ 11,658	$ 44,036	$ 2,638
Primary and fully diluted earnings per share:					
Before extraordinary item--------	$ 0.76	$ 0.66	$ 0.37	$ 1.69	$ 0.11
Extraordinary item---------------	--	--	0.05	--	--
Net income-----------------------	$ 0.76	$ 0.66	$ 0.42	$ 1.69	$ 0.11

(TABLE CONTINUED ON FOLLOWING PAGE)

SELECTED FINANCIAL AND OPERATING DATA -- (CONTINUED)

<CAPTION>

	YEAR ENDED DECEMBER 31,				
	1993	1992	1991	1990	1989
	(EXPRESSED IN THOUSANDS, EXCEPT PER SHARE AND UNIT AMOUNTS)				
<S>	<C>	<C>	<C>	<C>	<C>
BALANCE SHEET DATA (AT PERIOD END):					
Total assets-------------------------	$ 239,774	$ 206,347	$ 213,772	$ 244,226	$ 227,508
Long-term debt, excluding current					

portion	130,539	129,260	184,260	217,000	264,000
Production payment obligation, excluding current portion	--	14,337	37,805	43,019	47,036
Shareholders' equity (deficit)	33,803	5,648	(56,636)	(68,429)	(132,557)
PRODUCTION (SALES) DATA:					
Net daily average and weighted average price:					
Natural gas:					
Mcf per day	91,700	105,200	104,200	107,300	111,300
Price per Mcf	$ 1.98	$ 1.75	$ 1.66	$ 1.89	$ 1.88
Crude oil and condensate:					
Bbls per day	9,851	8,699	7,108	6,209	6,013
Price per Bbl	$ 17.81	$ 20.17	$ 20.98	$ 23.84	$ 18.86
Natural gas liquids:					
Bbls per day	1,678	1,181	663	697	948
Price per Bbl	$ 11.90	$ 13.50	$ 14.21	$ 13.75	$ 10.16
OTHER FINANCIAL DATA AND SELECTED RATIOS:					
Capital and exploration expenditures (excludes capitalized interest)	$ 74,600	$ 41,300	$ 53,100	$ 39,500	$ 25,800
EBITDA(b)	$ 96,381	$ 99,339	$ 81,637	$ 116,760	$ 87,384
EBITDA/Net interest expense	9.2	5.3	3.4	3.8	2.4
Ratio of earnings to fixed charges(c)	4.5	2.5	1.6	2.3	1.0
Long-term obligations/Total proved reserves (BOE)(d)	$ 1.95	$ 2.52	$ 4.22	$ 4.70	$ 5.49

(a) In late 1990, the Company entered into a settlement agreement with the Internal Revenue Service (the 'IRS') for a refund of $8,607,000 in taxes for taxable years 1976 through 1985 which, together with accrued interest of $20,395,000, resulted in a refund receivable of $29,002,000 through December 31, 1990. The refund and interest income together with the reversal of previously accrued interest expense of $2,104,000 contributed $23,456,000 or $0.90 per share to earnings in 1990. The refund and the additional accrued interest was received by the Company on May 31, 1991. In late 1993, the Company recognized $2,322,000 of interest income related to a settlement with the IRS for the refund of $998,000 in taxes for taxable years 1976 through 1984. The interest income contributed $1,509,000 or $0.05 per share to earnings in 1993.

(b) EBITDA represents income from continuing operations before provision for income taxes, interest expense, interest income, interest capitalized, depreciation and amortization, and dry hole and impairment costs. EBITDA is presented as a measure of the Company's debt service ability, and not as an alternative to (i) operating income (as determined in accordance with generally accepted accounting principles) as an indicator of the Company's operating performance, or (ii) cash flows from operating activities (as determined in accordance with generally accepted accounting principles) as a measure of liquidity.

(c) Income before taxes and extraordinary item plus fixed charges (net of capitalized interest) divided by fixed charges. Fixed charges are defined as interest expense plus the portion of rental expense representing interest.

(d) Long-term obligations include long-term debt (excluding current maturities) and the non-current portion of the Eugene Island Block 330 Production Payment obligation until such obligation was satisfied in 1993. Total proved reserves are expressed on an energy equivalent basis.
</TABLE>

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

RESULTS OF OPERATIONS

The Company reported net income for 1993 of $25,061,000 or $0.76 per share compared to net income for 1992 of $18,495,000 or $0.66 per share and net income for 1991 of $11,658,000 or $0.42 per share. Included in net income for 1991 are extraordinary gains of $1,336,000 or $0.05 per share in connection with purchases at less than face value of the Company's 8% Convertible Subordinated Debentures due 2005 (the '8% Debentures'). Earnings per common share are based on the weighted average number of shares of common and common equivalent shares outstanding for 1993 of 32,860,000 compared to 27,929,000 for 1992 and 27,611,000 for 1991. The increases in the weighted average number of common and common equivalent shares outstanding for 1993 primarily related to the issuance of 4,500,000 shares of Common Stock in December 1992 as set forth in the Consolidated Statements of Shareholders' Equity included in the 'Financial Statements' attached to, and forming a part of, this Prospectus.

The Company's total revenues for 1993 were $139,554,000, or approximately equal to total revenues of $140,830,000 for 1992, and an increase of approximately 12% from total revenues of $124,469,000 for 1991. The Company's oil and gas revenues for 1993 were $136,553,000, a slight decrease of approximately 2% from oil and gas revenues of $139,128,000 for 1992, and an increase of approximately 10% from oil and gas revenues of $124,425,000 for 1991. The following table reflects an analysis of variances in the Company's oil and gas revenues between 1993 and the previous two years:

	1993 COMPARED TO	
	1992	1991
	(IN THOUSANDS)	
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas		
Price	$ 8,738	$ 11,984
Production	(9,931)	(9,036)
	(1,193)	2,948
Crude oil and condensate		
Price	(7,514)	(8,209)
Production	7,332	17,831
	(182)	9,622
Natural gas liquids		
Price	(689)	(560)
Production	2,144	4,406
	1,455	3,846
Other, net	(2,655)	(4,288)
Increase (decrease) in oil and gas revenues	$ (2,575)	$ 12,128

Average natural gas prices received by the Company for the two years prior to 1991 were relatively stable. Though seasonal variations were experienced, the average annual prices received per Mcf were $1.88 for 1989 and $1.89 for 1990. The industry's perceived ability to deliver more natural gas on a daily basis than demanded by customers resulted in a decrease in the average annual price for 1991 to $1.66 per Mcf. Prices of natural gas reached a low in February 1992, when the Company's prices averaged only $1.13 per Mcf, during a time of typically high winter prices, due, in part, to decreased demand resulting from a milder than anticipated winter. The natural gas prices received by

the Company then began recovering again, averaging $1.75 per Mcf for 1992 and $1.98 per Mcf for 1993. Prices recovered after February 1992 due to late winter cold snaps which drew down natural gas storage supplies and created demand in the spring and summer to replenish storage facilities. In late August 1992, production in the Gulf of Mexico was shut-in for approximately four days as a result of Hurricane Andrew. This shut-in and decreased production from hurricane damage put upward pressure on natural gas prices for the balance of the year. Natural gas prices continued to strengthen in 1993, partially as a result of severe late winter weather that drew down natural gas storage supplies which, coupled with relatively high crude oil prices that inhibited fuel switching from natural gas to residual heating oil at that time, created a substantial demand in the spring and the summer to replenish depleted storage facilities and to supply natural gas for the industrial and electric generation markets.

Natural gas production in 1993 averaged 91.7 MMcf per day, a decrease of approximately 13% from average production of 105.2 MMcf per day in 1992, and a decrease of approximately 12% from average production of 104.2 MMcf per day in 1991. The Company's decrease in natural gas production during 1993 compared to prior periods was primarily related to decreased natural gas deliverability from certain of the Company's Gulf of Mexico wells; production downtime due to drilling, workover and maintenance operations designed to increase the Company's deliverability; weather related problems and the exchange of properties discussed in 'Business and Properties -- Domestic Offshore Acquisitions; Lease Acquisitions' which temporarily reduced the Company's delivery capacity. The Company anticipates that, as a result of its workover and drilling program, when natural gas production commences from its new platform currently under construction on Eugene Island Block 295 (which construction is scheduled, weather permitting, to be completed during March 1994) the Company's natural gas production will increase substantially from its average 1993 production rates.

Crude oil and condensate prices averaged $17.81 per Bbl in 1993 compared to $20.17 per Bbl in 1992 and $20.98 per Bbl in 1991. Crude oil and condensate prices were relatively stable during 1991, 1992 and the first six months of 1993. However, commencing in July 1993, the average price per Bbl that the Company received for its production began to decline until, by December 1993, the average price per Bbl for crude oil and condensate that the Company received for its production averaged only $13.39 per Bbl. The decrease in the average price that the Company receives for its crude oil and condensate production has resulted primarily from a worldwide excess of crude oil supplies resulting from increased production from both Organization of Petroleum Exporting Countries ('OPEC') and certain non-OPEC countries coupled with flat or only marginally increased demand from consumer countries. The Company has entered into a crude oil swap agreement with another party in which it swapped the floating market price it would receive from purchasers of its crude oil for a fixed price of $16.00 per Bbl on 1,000 Bbls per day of its production. The agreement expires July 31, 1994, but may be extended through January 31, 1995, at the other party's option.

Crude oil and condensate production for 1993 averaged 9,851 Bbls per day, an increase of approximately 13% from 8,699 Bbls per day for 1992, and an increase of approximately 39% from 7,108 Bbls per day for 1991. The increase in crude oil and condensate production was a result of ongoing development programs both offshore (primarily in the Eugene Island area) and onshore in several fields located in Lea and Eddy counties of southeastern New Mexico.

Liquid products are often extracted from natural gas streams and sold separately as natural gas liquids ('NGL'). The Company's NGL production averaged 1,678 Bbls per day for 1993, an increase of approximately 42% from an average of 1,181 Bbls per day for 1992 and an increase of approximately 153% from an average of 663 Bbls per day for 1991. The Company's NGL production during 1993, compared to prior periods, increased primarily as a result of extracting liquids from several new high Btu content wells, increased ownership interest in plants, and capital improvements which increased plant efficiency.

The Company's total liquids production during 1993, including crude oil, condensate and NGL, averaged 11,529 Bbls per day, an increase of approximately 17% from an average total liquids production of 9,880 Bbls per day for 1992, and an increase of approximately 48% from an average total liquids production of 7,771 Bbls per day for 1991.

'Other, net' revenues for 1993, 1992, and 1991 included, among others, the following significant items:

	1993	1992	1991
		(IN THOUSANDS)	
Offset of FERC Order 93A adjustments against FERC Order 94A obligations------------------------	$ --	$ 1,642	$ --
Natural gas sales contract settlement-------------------------	--	--	2,750
Gains on retirement of debt----------	--	--	646
Settlement of federal and state royalty disputes-------------------	(803)	(65)	--
Other, net----------------------------	(147)	128	(58)
	$ (950)	$ 1,705	$ 3,338

For 1993 and 1992, the Company made adjustments to its revenues to reflect the settlement of certain litigation with the State of Louisiana regarding past royalty disputes pertaining to the Company's offshore state leases. For 1992 additional adjustments were also made to reflect an agreement with the MMS to allow the Company to offset Federal Energy Regulatory Commission ('FERC') Order 93A payments previously made by the Company on behalf of the MMS against FERC Order 94A obligations due from the Company and the resulting overaccrual of related interest expenses. For 1991, the Company recorded adjustments to reflect the settlement of a dispute regarding a natural gas sales contract and the purchase, at a discount, of certain of 8% Debentures on the open market.

Lease operating expenses for 1993 were $26,633,000, an increase of approximately 3% from lease operating expenses of $25,842,000 for 1992, but a decrease of approximately 6% from lease operating expenses of $28,192,000 for 1991. The increase in lease operating expenses for 1993, compared to 1992, was primarily related to increased operating costs on existing properties, as well as increased operating costs related to additional properties brought on production in the second half of 1992. The increased operating costs were partially offset by lower maintenance costs. The decrease in lease operating expenses for 1993, compared to 1991, was primarily related to a decrease in special maintenance projects and to a decrease in lifting costs.

General and administrative expenses for 1993 were $14,550,000, an increase of approximately 11% from general and administrative expenses of $13,129,000 for 1992, but were essentially equal to general and administrative expenses of $14,555,000 for 1991. The increase in general and administrative expenses for 1993, compared to 1992, was primarily related to increased business insurance premiums resulting from the Company's increased drilling activity and insurance premium rate increases resulting from the insurance industry's recent loss experience in general, rather than losses specifically relating to the Company's operations, as well as normal salary adjustments and a 4% increase in the

Company's work force resulting from increased activity.

Exploration expenses consist primarily of delay rentals and geological and geophysical ('G&G') costs which are expensed as incurred. Exploration expenses for 1993 were $2,455,000, a decrease of approximately 21% from exploration expenses of $3,102,000 for 1992, and a slight increase of approximately 2% from exploration expenses of $2,408,000 for 1991. The decline in exploration expenses for 1993, compared to 1992, was primarily related to the costs of conducting a G&G survey, primarily in 1992, on the Company's oil and gas concession in the Kingdom of Thailand.

Dry hole and impairment expenses relate to costs of unsuccessful wells drilled along with impairments to the associated unproved property costs and impairments to previously proved property costs as a result of decreases in expected reserves. The Company's dry hole and impairment

expenses for 1993 were $4,690,000, a decrease of approximately 50% from dry hole and impairment expenses of $9,314,000 for 1992, but a slight increase of approximately 3% from dry hole and impairment expenses of $4,554,000 for 1991.

The Company accounts for its oil and gas activities using the successful efforts method of accounting. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs are expensed as incurred.

The provision for depreciation, depletion and amortization ('DD&A') is determined on a field-by-field basis using the units of production method. The Company's DD&A expense for 1993 was $40,693,000, a decrease of approximately 4% from DD&A expenses of $42,302,000 for 1992, but an increase of approximately 8% from DD&A expenses of $37,521,000 for 1991. The decreases in the Company's DD&A expenses for 1993, compared to 1992, were primarily due to a decrease in natural gas production. The increases in the Company's DD&A expenses for 1993, compared to 1991, were primarily related to increased volumes produced (largely related to the increased crude oil and condensate production discussed earlier) and, to a lesser extent, an increase in the composite DD&A rate. See 'Financial Statements -- Note 1 of Notes to Consolidated Financial Statements.'

Interest charges for 1993 were $10,956,000, a decrease of approximately 42% from interest charges of $19,036,000 for 1992 and a decrease of approximately 56% from interest charges of $24,946,000 for 1991. The decrease in interest expense for 1993, compared to 1992 and 1991, related primarily to the retirement or refinancing of high cost debt at more favorable interest rates and the reduction in total debt to $134,539,000 on December 31, 1993, from $158,114,000 (including the production payment obligation) on December 31, 1992, a decrease of approximately 15%. In addition, interest expense has also been reduced, to a limited extent, by decreases in applicable floating interest rates. As of December 31, 1993, the Company had entered into swap agreements on $15,000,000 of its bank debt, $5,000,000 of which terminated in January 1994 and $10,000,000 of which terminates in July 1994. The swap agreements on the bank debt effectively change the interest the Company pays on its bank debt from variable rates to fixed rates which average 5.78% on the $15,000,000.

LIQUIDITY AND CAPITAL RESOURCES

The Consolidated Statement of Cash Flows for the year ended December 31, 1993 reflects net cash provided by operating activities of $83,144,000, proceeds from sales of tubular stock and non-strategic properties of $2,713,000 and cash received from stock options exercised of $2,026,000. The Company invested $62,353,000 of such cash flow in capital projects during 1993. The Company continued to reduce its total debt and production payment obligation from $158,114,000 at December 31, 1992 to $134,539,000 at December 31, 1993, a decrease of $23,575,000 or approximately 15% of the Company's combined debt and Eugene Island 330 production payment obligation since the end of 1992, and a decline of approximately 42% in its combined debt and Eugene Island 330 production payment obligation since the end of 1991. During 1993, the Company retired its Eugene Island 330 production payment obligation. The Company's cash and cash investments were $6,713,000 at December 31, 1993.

The Company's capital and exploration budget for 1994 has been established by the Company's Board of Directors at $75,000,000, or approximately equal to the Company's capital and exploration expenditures of approximately $74,600,000 for 1993, an increase of 82% over capital and exploration expenditures of approximately $41,300,000 for 1992 and an increase of 41% over capital and exploration expenditures of approximately $53,100,000 for 1991.

In addition to anticipated capital and exploration expenses as of December 31, 1993, other material 1994 cash requirements that the Company anticipates include ongoing operating, general

and administrative, income tax, and interest expenses. Cash requirements for future payments of federal income taxes are expected to be greater than those experienced in the immediate past. The increased tax payments result from expected increases in taxable income, increased tax rates and the utilization in 1993 and prior years of available tax credits and net operating tax loss carry-forwards. The Company currently anticipates that cash provided by operating activities and funds available under its Credit Agreement will be sufficient to fund the Company's ongoing expenses and the Company's 1994 capital and exploration budget. See 'Use of Proceeds.'

As of December 31, 1993, the Company amended its bank credit agreement (the 'Credit Agreement'). The Credit Agreement currently provides for a $100,000,000 revolving/term credit facility which will be fully revolving until June 29, 1996, after which the balance will be due in eight quarterly term loan installments, commencing July 31, 1996. The amount that may be borrowed under the Credit Agreement may not exceed a borrowing base, determined semiannually by the lenders in accordance with the Credit Agreement, based on the discounted present value of certain of the Company's oil and gas reserves. The borrowing base currently exceeds $100,000,000. The Credit Agreement is governed by various financial and other covenants, including requirements to maintain positive working capital and a specified fixed charge ratio and limitations on debt, dividends, mergers and consolidations and asset dispositions. See 'Price Range of Common Stock and Dividends.' Upon the occurrence or declaration of certain events, the banks would be entitled to a security interest in the borrowing base properties, which include substantially all of the Company's domestic properties. Borrowings under the Credit Agreement bear interest at Base (Prime) rate plus 1/4%, a certificate of deposit rate plus 1 7/8%, or LIBOR plus 1 3/4%, at the Company's option. A commitment fee of 1/2 of 1% per annum of the unborrowed amount under the Credit Agreement is also due. As of December 31, 1993, indebtedness in the principal amount of $67,000,000 was outstanding under the Credit Agreement.

The outstanding principal amount of the 10.25% Notes was $24,000,000 as of December 31, 1993. The 10.25% Notes are convertible into Common Stock at $23.95 per share, subject to adjustment in certain circumstances, including stock splits, and require annual sinking fund payments of $4,000,000 each April, with a final maturity of April 1, 1999. A portion of the proceeds of the Offering will be used to repay the 10.25% Notes in full. See 'Use of Proceeds.' The outstanding principal amount of the 8% Debentures was $43,539,000 as of December 31, 1993. The 8% Debentures are convertible into Common Stock at $39.50 per share, subject to adjustment in certain circumstances, including stock splits, and are also subject to mandatory annual sinking fund requirements of $3,000,000 due each December, with a final maturity of December 31, 2005. The Company currently has $4,460,000 face amount of 8% Debentures which it may tender in satisfaction of future sinking fund requirements. See 'Financial Statements -- Note 3 to Notes to Consolidated Financial Statements.'

OTHER MATTERS

Publicly held companies are asked to comment on the effects of inflation on their business. Currently annual inflation in terms of the decrease in the general purchasing power of the dollar is running much below the general annual inflation rates of several years ago. While the Company, like other companies, continues to be affected by fluctuations in the purchasing power of the dollar, such effect is not currently considered significant.

BUSINESS AND PROPERTIES

GENERAL

The Company was incorporated in 1970 and is engaged in oil and gas exploration, development and production activities on its properties located offshore in the Gulf of Mexico and onshore in the United States. The Company is also engaged in exploration of its license concession in the Gulf of Thailand, and is evaluating a development program in connection with its recently announced oil and gas discoveries on that concession. The Company has interests in 76 lease blocks offshore Louisiana and Texas, approximately 93,000 gross acres onshore in the United States, approximately 2,635,000 gross acres offshore in the Kingdom of Thailand, and approximately 1,965,000 gross acres in Australia. The Company, which historically has not operated a substantial percentage of its offshore properties, has assumed operatorship of certain of its properties where the Company believes that its technical expertise and ability to control overhead and operating costs will enhance its economic interests.

DOMESTIC OFFSHORE OPERATIONS

Historically, the Company's interests have been concentrated in the Gulf of Mexico, where approximately 81% of the Company's domestic proved reserves and 68% of its total proved reserves are now located. During 1993, approximately 75% of the Company's natural gas equivalent production was from its domestic offshore properties, contributing approximately 75% of consolidated oil and gas revenues. Four offshore producing areas, Eugene Island, South Marsh Island, Main Pass and East Cameron, account for approximately 52% of the Company's net proved natural gas reserves and approximately 56% of the Company's proved crude oil, condensate and natural gas liquids reserves. Eugene Island is the Company's largest producing area with 1993 average net revenue interest production (net to the Company's interest and net of royalty burdens) of 24 MMcf per day of natural gas and 4,600 Bbls per day of oil, condensate and natural gas liquids.

LEASE ACQUISITIONS

The Company has participated with other companies in bidding on and acquiring interests in federal leases offshore in the Gulf of Mexico since December 1970. As a result of such sales and subsequent activities, the Company owns interests in 70 federal leases offshore Louisiana and Texas. Federal leases generally have primary terms of five years, subject to extension by development and production operations. The Company also owns interests in six leases in state waters offshore Louisiana.

As part of its strategy, the Company intends to continue an active lease evaluation program in the Gulf of Mexico in order to identify exploration and exploitation opportunities. The Department of the Interior has announced its intention to hold two lease sales during 1994 covering federal acreage in the Central and Western portions of the Gulf of Mexico; and it is anticipated that various states will also hold sales covering state acreage from time to time. As in the case of prior sales, the extent to which the Company participates in future bidding will depend on the availability of funds and its estimates of hydrocarbon deposits, operating expenses and future revenues which reasonably may be expected from available lease blocks. Such estimates typically take into account, among other things, estimates of future hydrocarbon prices, federal regulations, and taxation policies applicable to the petroleum industry.

It is also the Company's objective to acquire certain producing properties where additional low_risk drilling or improved production methods by the Company can provide attractive rates of return. During 1993, the Company acquired a 50% working interest in South Pass Block 50 and acquired an additional approximately 17% working interest in Ship Shoal Block 240. In late 1993, the Company effected an exchange of working interests in certain federal offshore lease blocks with another working interest owner in such blocks. As a result of this exchange, the Company increased its working interest in the following five blocks: Eugene Island 256 (from 41.5% to 69.2%), Eugene Island 295 (from 60% to 100% on 3,125 acres above 3,000 feet, from 12% to 20% on 1,875 acres

above 3,000 feet and from 12% to 20% on all of the block below 3,000 feet), Eugene Island 261 (from 43.3% to 66.6%) and West Cameron blocks 252 and 253 (from 24% to 80%). In exchange, the Company assigned various working interests in 13 blocks to the other working interest owner. The Company effected the exchange primarily because it believes that this exchange will result in significant increased exploitation and exploration potential in the Eugene Island and West Cameron areas. This exchange of working interests is also consistent with the Company's strategy of increasing its working interest in its core areas. In connection with this exchange, the Company became the operator for the joint venture partners on certain of these blocks.

EXPLORATION AND DEVELOPMENT

The scope of exploration and development programs relating to the Company's offshore interests is affected by prices for oil and gas, and by federal, state and local legislation, regulations and ordinances applicable to the petroleum industry. The Company's domestic offshore capital and exploration expenditures for 1993 were approximately $39,000,000, or 122% higher than the Company's domestic offshore capital and exploration expenditures of approximately $17,600,000 for 1992 and 23% higher than the Company's domestic offshore capital and exploration expenditures of approximately $31,700,000 for 1991. Development and production related projects represented 86% of the Company's 1993 domestic offshore capital and exploration expenditures. See 'Management's Discussion and Analysis of Financial Condition and Results of Operations.'

Leases acquired by the Company and other participants in its bidding groups are customarily committed, on a block-by-block basis, to separate operating agreements under which the appointed operator supervises exploration and development operations for the account and at the expense of the group. These agreements usually contain terms and conditions which have become relatively standardized in the industry. Major decisions regarding development and operations typically require the consent of at least a majority (in working interest) of the participants. Because the Company generally has a meaningful working interest position, the Company believes it can influence decisions regarding development and operations even though it may not be the operator of a particular lease. The Company, which historically has not operated a substantial portion of its offshore properties, has assumed the operation of certain of its properties where the Company believes that its technical expertise and ability to control overhead and operating costs will enhance its economic interest.

Platforms are installed on a block when, in the judgment of the lease interest owners, the necessary capital expenditures are justified. A decision to install a platform generally is made after the drilling of one or more exploratory wells with contracted drilling equipment. Platforms are used to accommodate both development drilling and additional exploratory drilling. In recent years, the gross cost of production platforms to the joint ventures in which the Company has varying net interests has been less than $11,000,000 per platform. Platform costs vary and more expensive platforms could be required in the future depending on, among other factors, the number of slots, water depth, currents, and sea floor conditions. During 1993, the Company commenced installation of an additional platform on Eugene Island Block 295 and announced its intention to set a platform on Main Pass Block 123. See '-- Principal Properties.'

In 1989, the Company entered into a limited partnership agreement as general partner of Pogo Gulf Coast, Ltd., a Texas limited partnership ('Pogo Gulf Coast'), in which the Company agreed to be responsible for investing as much as $60,000,000 on behalf of Pogo Gulf Coast for acquisition and exploration in state and federal waters in the Gulf of Mexico. As of December 31, 1993, Pogo Gulf Coast had interests in 24 federal offshore leases, and had invested a total of $41,750,000 of the aforementioned $60,000,000. The Company owns 40% of any interest in properties acquired by the limited partnership. Unless otherwise noted, the statistical data reported in this Prospectus reflect only the Company's share of Pogo Gulf Coast's holdings.

DOMESTIC ONSHORE OPERATIONS

The Company has onshore division staffs in Houston and Midland, Texas. Its onshore activities are concentrated in known oil and gas provinces, principally the Permian Basin of southeastern New Mexico and West Texas and the onshore Gulf Coast area. As of December 31, 1993, the Company and its partners had drilled and completed as productive 151 consecutive wells in Lea and Eddy Counties in southeastern New Mexico, including 58 wells in 1993 alone. The Company's primary drilling objective in southeastern New Mexico is the Brushy Canyon (Delaware) formation which produces oil at depths of 6,000 to 9,000 feet. The Company's net revenue interest portion of daily liquid hydrocarbon production in New Mexico averaged approximately 3,700 Bbls during 1993, which represented approximately 32% of the Company's total average daily production of oil, condensate and liquid plant products during 1993.

The Company generally conducts its onshore activities through joint ventures and other interest-sharing arrangements with major and independent oil companies. The Company operates many of its onshore properties using independent contractors.

The Company's domestic onshore capital and exploration expenditures were approximately $29,400,000 for 1993, or 44% higher than the Company's domestic onshore capital and exploration expenditures of approximately $20,400,000 for 1992 and 56% higher than the Company's domestic onshore capital and exploration expenditures of approximately $18,800,000 for 1991. Development and production related projects represented 82% of the Company's 1993 domestic onshore capital and exploration expenditures. As of December 31, 1993, the Company held leases on 56,155 net acres onshore in the United States. Onshore reserves as of December 31, 1993, accounted for approximately 19% of the Company's domestic proved reserves and approximately 16% of its total proved reserves. During 1993, approximately 25% of the Company's natural gas equivalent production was from its domestic onshore properties, contributing approximately 25% of consolidated oil and gas revenues.

INTERNATIONAL OPERATIONS

The Company has conducted international exploration activities since the late 1970's in numerous oil and gas areas in various parts of the world. The Company pursues a strategy of evaluating potentially high return prospects in areas of the world with a stable political and financial climate such as certain European and ASEAN countries. In 1988, the Company sold its United Kingdom reserves which were located in the North Sea. Since that time, the Company has analyzed several opportunities and has obtained a concession in the Kingdom of Thailand and a concession in Australia. The Company's international capital and exploration expenditures were approximately $6,000,000 for 1993, or 131% higher than the Company's international capital and exploration expenditures of approximately $2,600,000 for 1992. Substantially all of the Company's international capital and exploration expenditures for 1993 were related to the Company's license in the Kingdom of Thailand. However, the Company continues to evaluate other international opportunities that are consistent with the Company's international exploration strategy.

In 1990, the Company invited Rutherford/Moran Oil Company ('Rutherford/Moran'), Maersk Olie og Gas A/S ('Maersk') and Sophonpanich Co., Ltd. ('Sophonpanich') to join it in bidding for a concession license on Block B8/32, a 2.6 million acre tract in the Gulf of Thailand. In August 1991, the Company, Rutherford/Moran, Maersk and Sophonpanich were awarded a license from the Kingdom of Thailand to explore for and produce oil and gas on the tract. The Company's working interest in the concession is 31.67%. Maersk is the operator with a similar 31.67% interest.

Exploration activities in Thailand are consistent with the Company's objectives of expanding its international operations in areas that have geological features which the Company believes may be favorable for hydrocarbon accumulation, low entry costs, an acceptable political risk profile and operational or other similarities with the Company's existing activities. Thailand is expected to be a net importer of hydrocarbons at least through the year 2000, which should provide an attractive

market for hydrocarbons produced locally. The Company's acreage is located 150 miles south southeast of Bangkok in 250 feet of water and is on trend with several producing oil and gas fields including, among others, the Erawan, Surat and Satun fields. The tract is traversed by a major natural gas pipeline. The Company understands that a contract has been entered into for construction of a second, parallel pipeline owned by an entity controlled by the government of the Kingdom of Thailand, with completion scheduled for early 1996. The Company anticipates that by the time production can commence from this concession, there should be ample transportation capacity available on these pipelines.

Following an initial evaluation of the Thailand concession area, the Company and its joint venture partners drilled five exploratory wells on three separately identified seismic structures. In October 1992, the first well drilled, the Tantawan No. 1, successfully tested a large, complexly faulted, anticlinal structure with production tests from five intervals in that well resulting in calculated cumulative flow rates of 6,260 Bbls of oil and condensate and 25,750 Mcf of natural gas per day. During 1993, the Company and its joint venture partners shot, processed and evaluated approximately 9,000 kilometers of new 3-D seismic data over and around the Tantawan No. 1 well. In late 1993, the Company drilled the Tantawan No. 2 and the Tantawan No. 3 exploratory wells on the Tantawan structure. The Tantawan No. 2 well successfully delineated a previously untested fault block to the east of the Tantawan No. 1 well with production tests from six intervals resulting in calculated cumulative flow rates of 70,300 Mcf of natural gas and 1,720 Bbls of condensate per day. The Tantawan No. 3 well successfully delineated a third untested fault block on the Tantawan structure located approximately two miles north of the Tantawan No. 1 and No. 2 wells. Production tests from this third Tantawan well were reported in January 1994, with production tests from five intervals resulting in calculated cumulative flow rates of 40,660 Mcf of natural gas and 8,684 Bbls of oil and condensate per day.

As a result of its successful exploration drilling program, the Company's Thailand concession now accounts for approximately 14% of the Company's total estimated net proved reserves of natural gas, approximately 19% of the Company's total estimated net proved reserves of oil, condensate and natural gas liquids and approximately 16% of the Company's total net proved oil and gas equivalent reserves. Additional delineation wells on the Tantawan structure are planned during 1994. Based upon the results of such drilling, the Company and its partners will agree upon the type of development plan needed to commence production in this area. In addition, in late 1993, the Company and its joint venture partners began shooting and processing additional new 3-D seismic data in a different portion of Block B8/32. Following evaluation of this seismic data, additional exploratory wells are expected to be drilled by the Company and its joint venture partners on as yet untested seismic structures identified on Block B8/32.

Production from the concession will be subject to a royalty ranging from 5% to 15% of oil and gas sales, plus certain fixed dollar amounts payable at specified cumulative production levels. Revenue from production in Thailand will also be subject to income taxes and other governmental charges. As set forth in the August 1991 concession, the exploratory term of the concession is for a period of up to six years; provided, however, that after the expiration of four years, a portion of the acreage in Block B8/32 must be relinquished by the Company and its joint venture partners and removed from the concession license. The Company must identify and release this acreage no later than August 1, 1995. During the remainder of the concession's exploratory period, the Company and its joint venture partners have certain work commitments involving the drilling of four more exploratory wells or the expenditure of certain sums of money on exploration activities. The Company anticipates, based on the joint venture's current exploration budget and capital spending plans, that it and its joint venture partners will satisfy the remainder of the concession's work commitments by the middle of 1995. Following the commencement of production, the initial production period of the concession is 20 years, subject to extension.

The Company also holds interests in three Authority to Prospect ('ATP') licenses in Australia. One ATP, in which the Company holds a 7.5% interest, covers 480,000 acres and expires in February 1995 unless certain expenditures are made. The Company has farmed out the other two ATP's to a third party and retained a small carried interest. None of the ATP's requires material expenditures by the Company.

PRINCIPAL PROPERTIES

As of January 1, 1994, approximately 81% of the Company's domestic proved oil and gas equivalent reserves and approximately 68% of the Company's total proved oil and gas equivalent reserves were located on properties in the Gulf of Mexico. Five significant producing areas, of which four are located in the Gulf of Mexico and the fifth is located in New Mexico, accounted for approximately 59% of the estimated proved natural gas reserves and approximately 74% of the estimated oil, condensate and natural gas liquids reserves of the Company as of January 1, 1994. These producing areas accounted for approximately 60% of natural gas production and 90% of oil, condensate and natural gas liquids production for 1993. Reserves and production data for the five principal producing areas, as estimated by Ryder Scott, are shown in the following table. No other major producing area accounted for more than 5% of the estimated discounted future net revenues attributable to the Company's estimated proved reserves as of January 1, 1994. However, the Company's Thailand concession, which is currently not a producing property, accounts for approximately 14% of the Company's total estimated net proved reserves of natural gas, approximately 19% of the Company's total estimated net proved reserves of oil, condensate and natural gas liquids and approximately 16% of the Company's total net proved oil and gas equivalent reserves.

<TABLE>

SIGNIFICANT PRODUCING AREAS

<CAPTION>

	NET PROVED RESERVES AS OF JANUARY 1, 1994				1993 AVERAGE NET DAILY PRODUCTION			
	NATURAL GAS		LIQUIDS(A)		NATURAL GAS		LIQUIDS(A)	
	(MMCF)	%	(MBBLS)	%	(MCF)	%	(BBLS)	%
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
OFFSHORE								
Eugene Island----------------------	92,742	39.8%	10,448	37.0%	24,000	27.1%	4,600	39.8%
South Marsh Island-----------------	6,811	2.9	2,579	9.1	2,101	2.4	1,378	11.9
Main Pass--------------------------	9,186	3.9	2,722	9.6	3,721	4.2	598	5.2
East Cameron-----------------------	12,423	5.3	75	0.3	13,852	15.6	76	0.7
ONSHORE								
New Mexico								
Lea/Eddy Counties----------------	16,219	7.0	4,994	17.7	9,660	10.9	3,714	32.1

<CAPTION>

	DISCOUNTED FUTURE NET REVENUES(B)
	%
<S>	<C>
OFFSHORE	
Eugene Island----------------------	53.3%
South Marsh Island-----------------	5.1
Main Pass--------------------------	4.5
East Cameron-----------------------	4.2
ONSHORE	
New Mexico	
Lea/Eddy Counties----------------	9.9

(a) 'Liquids' includes oil, condensate and natural gas liquids.
(b) Before income taxes, discounted at 10%.
</TABLE>

Set forth below are descriptions of certain of the Company's significant producing areas. Contained in certain of these descriptions and elsewhere in this Prospectus are production rate test results with regard to certain wells and fields in which the Company has an interest. Such production rate tests, while accurate, are never indicative of actual sustained production rates.

EUGENE ISLAND

The Company's most significant reserves are in the Eugene Island area located off the Louisiana coast in the Gulf of Mexico. The Eugene Island area has been an important part of the Company's operations since the first lease in that area was purchased in 1970 and production began in 1973. The Company currently holds interests in 13 blocks in the Eugene Island area. These comprise eight fields containing 90 gross oil and gas wells producing from multiple reservoirs and horizons.

The Eugene Island Block 330 field is the Company's most significant asset, with 28 productive Pleistocene horizons between 4,000 and 8,000 feet, containing multiple reservoirs. The field, located

in 245 feet of water, contains three drilling and production platforms in which the Company holds a 35% working interest, as well as an additional platform in which the Company holds a 30% working interest. There are currently 18 wells producing primarily natural gas and 35 wells producing primarily oil on the block. In 1993, a successful five well drilling program was completed in the field which included one horizontal and four vertical wells. A multi-well program off of the field's 'D' platform commenced in early January 1994. Since initial production in 1973, the Eugene Island Block 330 field has produced approximately 619 Bcf of natural gas and 122 MMBbls of oil and condensate (167 Bcf and 35 MMBbls, attributable to the Company's net revenue interest). Reserves have been added to this field consistently since production commenced. These increases have been derived from new exploratory horizons, infill drilling, field expansions and higher than anticipated recovery efficiencies.

Another significant field to the Company is Eugene Island Block 295. In production since 1973, this block has recorded gross production of over 387 Bcf of natural gas and over 2.9 MMBbls of oil and condensate during its twenty-year life. In August 1993, the Company effected an exchange of working interests in Eugene Island Block 295 with another working interest owner in such block. Pursuant to this exchange, the Company increased its working interest in Eugene Island Block 295 to 100% on 3,125 acres above 3,000 feet, to 20% on 1,875 acres above 3,000 feet and to 20% on all of the block below 3,000 feet. During the fourth quarter of 1993, the Company successfully drilled and completed five horizontal wells to exploit the natural gas potential located in certain shallow reservoirs on this block in an area where it has a 100% working interest. These five wells tested at a gross calculated cumulative daily flow rate of 100 MMcf of natural gas per day, although platform compression capacity and lease burdens dictate that ultimate net production volumes will be substantially less than this amount. The Company completed construction of a production platform over these wells and commenced initial production from the first of these wells in late February 1994.

The Eugene Island 212 field consists of Eugene Island Blocks 211 and 212 and Ship Shoal Block 175. The field contains eight productive horizons which have four oil wells and one natural gas well producing from a platform set in 1985. The Company and its partners drilled a successful infill development well in this field during the second half of 1993.

SOUTH MARSH ISLAND

The Company currently owns five blocks in the South Marsh Island area, located offshore Louisiana. Three of the leases were acquired in 1974, a fourth in 1980 and the most recent in 1992. Three blocks contain a total of five drilling and production platforms. These platforms currently have 44 oil and gas wells producing from Pleistocene age sandstone reservoirs located at depths from 5,000 to 10,000 feet.

The South Marsh Island 128 field, in which the Company owns a 16% working interest, comprises South Marsh Island Blocks 125, 127 and 128. This field primarily produces oil, with 36 oil wells and six natural gas wells producing from 20 separate reservoirs. The first four wells in a supplemental five-well drilling program in this field were completed in 1993. The current drilling program is based on the ongoing analysis of a 3-D seismic survey in conjunction with a detailed reservoir study of the field.

The Company also owns a 25% working interest in the South Marsh Island Block 160 field which is producing from two oil wells at a depth of approximately 9,700 feet. A single platform was set on this block in 1983. A two-well drilling program is currently being considered in this field as a result of recent analysis of a 3-D seismic survey on the block.

MAIN PASS

The Company's nine blocks in the Main Pass area are located near the mouth of the Mississippi River in the Gulf of Mexico and include leases purchased from 1974 to 1992. The primary drilling

objectives in these fields are Pliocene and Miocene sandstone reservoirs with productive formation depths from 5,000 to 12,000 feet. The Company's interests in the Main Pass area include 57 producing oil and gas wells producing from six platforms.

A field including Main Pass Blocks 72, 73 and 72/74 was unitized in 1982 with the Company's working interest at 14%. This field contains 33 oil wells and 11 natural gas wells operated by one of the Company's joint venture partners. The field is located in 125 feet of water with 38 mapped horizons adjacent to and surrounding a salt dome. These horizons contain over 150 separate reservoirs between 5,000 and 12,000 feet. A successful three-well workover program in this field was completed in 1992. Many of the producing reservoirs in this field have consistently outperformed their initial recovery estimates. Based on the high historical recovery efficiency, it is anticipated that some of the multiple behind pipe reservoirs remaining will also outperform their existing reserve estimates.

Main Pass Block 123 was acquired in the federal lease sale of 1990. Pogo Gulf Coast, for which the Company is the general partner, has a 75% working interest and is the operator on the block. Along with its non-operating joint venture partner, Pogo Gulf Coast drilled two discovery wells on the block in 1993 and is currently planning additional drilling as well as the installation of a production platform in late 1994.

EAST CAMERON

The original lease purchased by the Company and its partners in the East Cameron area off the Texas/Louisiana border in the Gulf of Mexico commenced production in February 1973. Presently, the Company has interests in 4 offshore blocks in this area which contain three fields and 16 producing gas wells.

During 1992, the Company and its partners conducted a 3-D seismic survey of the East Cameron Block 334/335 field area where the Company has a 42% working interest. The Company currently anticipates commencing a multi-well drilling program in this field during the first half of 1994.

NEW MEXICO

The Company considers southeastern New Mexico to be an area of significant growth in both production and reserves as a result of recent exploration and development activities. The Company believes that during the past four years it has been one of the most active companies drilling for oil and natural gas in the southeastern New Mexico (Lea and Eddy Counties) portion of the Permian Basin where the Company has interests in over 50,000 gross acres. The Company's primary drilling objective is the Brushy Canyon (Delaware) formation. Fields in the Brushy Canyon (Delaware) formation in the southeastern New Mexico portion of the Permian Basin are generally characterized by production from relatively shallow depths (6,000 to 9,000 feet), multiple producing zones in most wells and relatively high initial rates of production (frequently equaling the top field allowables which range from of 142 Bbls to 230 Bbls per day, depending on the depth of production from the field). The Company has achieved rapid cost recovery with respect to its New Mexico wells drilled to date because of relatively low capital costs and high initial rates of production.

Through December 31, 1993, the Company and its partners had drilled and completed as productive 151 consecutive wells in Lea and Eddy Counties including, among others, 52 wells in the Sand Dunes field where the Company's working interest ranges from 4% to 89%; 27 wells in the East Loving field where the Company's working interest ranges from 1.5% to 100%; 43 wells in the Livingston Ridge field where the Company's working interest ranges from 25% to 100%; and 8 wells in the Red Tank field where the Company's working interest ranges from 86% to 100%. The oil fields in this area are generally developed on 40 acre spacings. The Company anticipates drilling many additional locations in these and other fields in southeastern New Mexico during 1994 and in future years.

RESERVES

The following table sets forth information as to the Company's net proved and proved developed reserves as of December 31, 1993, 1992, and 1991, and the present value as of such dates (based on an annual discount rate of 10%) of the estimated future net revenues from the production and sale of those reserves, as estimated by Ryder Scott in accordance with criteria prescribed by the Commission. The summary report of Ryder Scott on the reserve estimates, which includes definitions and assumptions, is set forth as an exhibit to the Annual Report.

	AS OF DECEMBER 31,		
	1993	1992	1991
Total Proved Reserves:			
Oil, condensate, and natural gas liquids (MBbls)			
Located in the United States-----	22,843	19,979	18,818
Located in the Kingdom of Thailand-----------------------	5,425	2,577	--
Total Company--------------------	28,268	22,556	18,818
Natural Gas (MMcf)			
Located in the United States-----	199,392	196,400	202,735
Located in the Kingdom of Thailand-----------------------	33,474	10,668	--
Total Company--------------------	232,866	207,068	202,735
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in the United States-----	$386,674	$390,893	$349,754
Located in the Kingdom of Thailand-----------------------	17,166	14,208	--
Total Company--------------------	$403,840	$405,101	$349,754
Proved Developed Reserves (all located in the United States):			
Oil, condensate, and natural gas liquids (MBbls)----------------	20,976	18,798	17,550
Natural Gas (MMcf)---------------	183,139	175,523	188,090
Present value of estimated future net revenues, before income taxes (in thousands)-----------	$375,287	$378,300	$337,524

Natural gas liquids comprise approximately 14% of the Company's total proved liquids reserves and approximately 18% of the Company's proved developed liquids reserves. All hydrocarbon liquid reserves are expressed in standard 42 gallon Bbls. All gas volumes and gas sales are expressed in MMcf at the pressure and temperature bases of the area where the gas reserves are located.

Because of the direct relationship between quantities of proved undeveloped reserves and development plans, only reserves assigned to undeveloped locations that will definitely be drilled and reserves assigned to the undeveloped portions of secondary or tertiary projects that will definitely be developed have been included as proved undeveloped reserves.

The Company has interests in certain tracts that may have substantial additional hydrocarbon quantities which cannot be classified as proved. The Company has active exploratory and development drilling programs which may result in the reclassification of significant additional quantities as proved reserves.

The Company does not believe that any other major discovery or other favorable or adverse event causing a significant change in the estimated quantities of proved reserves has occurred since January 1, 1994.

ACREAGE

The following table shows the Company's interest in developed and undeveloped oil and gas acreage as of December 31, 1993:

	DEVELOPED ACREAGE (A)		UNDEVELOPED ACREAGE (B)	
	GROSS	NET	GROSS	NET
ONSHORE				
Arkansas-------------------------	--	--	118	20
Colorado-------------------------	--	--	7,963	7,963
Louisiana------------------------	869	258	--	--
New Mexico-----------------------	14,013	6,950	36,317	29,161
Oklahoma-------------------------	3,840	374	--	--
Texas----------------------------	11,677	4,541	17,849	6,853
Wyoming--------------------------	--	--	120	35

Total Onshore----------------	30,399	12,123	62,367	44,032
OFFSHORE				
Louisiana (State)----------------	7,804	2,964	--	--
Louisiana (Federal)(c)-----------	169,193	51,734	89,989	19,765
Texas (Federal)------------------	46,080	7,971	17,280	3,340
Total Offshore---------------	223,077	62,669	107,269	23,105
TOTAL DOMESTIC-------------------	253,476	74,792	169,636	67,137
INTERNATIONAL				
Thailand (Offshore)--------------	--	--	2,635,116	878,372
Australia (Onshore)--------------	--	--	1,964,800	42,960
TOTAL INTERNATIONAL--------------	--	--	4,599,916	921,332
TOTAL COMPANY------------------------	253,476	74,792	4,769,552	988,469

(a) 'Developed acreage' consists of lease acres spaced or assignable to production on which wells have been drilled or completed to a point that would permit production of commercial quantities of oil and natural gas.

(b) Approximately 38% of the Company's total offshore net undeveloped acreage is under leases that have terms expiring in 1994, if not held by production, and another approximately 21% of offshore net undeveloped acreage will expire in 1995 if not also held by production. Approximately 16% of onshore net undeveloped acreage is under leases that have terms expiring in 1994, if not held by production, and another approximately 39% of onshore net undeveloped acreage will expire in 1995 if not also held by production.

(c) The Company also owns overriding royalty interests in one federal lease offshore Louisiana totaling 5,000 gross and 1,250 net acres.

PRODUCTIVE WELLS AND DRILLING ACTIVITY

The following table shows the Company's interest in productive oil and natural gas wells as of December 31, 1993. Productive wells are producing wells plus wells 'capable of production' (e.g., natural gas wells waiting for pipeline connections or necessary governmental certification to commence deliveries and oil wells waiting to be connected to production facilities).

	OIL WELLS(A)		NATURAL GAS WELLS(A)	
	GROSS	NET	GROSS	NET
Offshore United States---------------	199	36.6	170	46.8
Onshore United States----------------	163	92.2	65	24.6
Total--------------------	362	128.8	235	71.4

(a) One or more completions in the same bore hole are counted as one well. The data in the above table includes 30 gross (5.8 net) oil wells and 16 gross (5.8 net) gas wells with multiple completions.

The following table shows the number of successful gross and net exploratory and development wells in which the Company has participated and the number of gross and net wells abandoned as dry holes during the periods indicated. An onshore well is considered successful upon the installation of permanent equipment for the production of hydrocarbons. Successful offshore wells consist of exploratory or development wells that have been completed or are 'suspended' pending completion (which has been determined to be feasible and economic) and exploratory test wells that were not intended to be completed and that encountered commercially producible hydrocarbons. A well is considered a dry hole upon reporting of permanent abandonment to the appropriate agency.

<TABLE>
<CAPTION>

	1993		1992		1991	
	SUCCESSFUL	DRY	SUCCESSFUL	DRY	SUCCESSFUL	DRY
<S>	<C>	<C>	<C>	<C>	<C>	<C>
GROSS WELLS						
Offshore United States						
Exploratory----------------------	5.0	1.0	--	2.0	2.0	3.0
Development----------------------	15.0	0	5.0	--	13.0	--
Onshore United States						
Exploratory----------------------	3.0	4.0	4.0	2.0	2.0	4.0
Development----------------------	61.0	1.0	34.0	--	32.0	--
Offshore Kingdom of Thailand						
Exploratory----------------------	2.0	2.0	1.0	--	--	--
Total--------------------	86.0	8.0	44.0	4.0	49.0	7.0
NET WELLS						
Offshore United States						
Exploratory----------------------	1.7	0.1	--	0.7	0.2	0.4
Development----------------------	7.7	--	1.5	--	4.0	--
Onshore United States						

Exploratory	2.0	3.2	2.8	0.9	1.0	2.3
Development	33.1	0.4	23.2	--	18.2	--
Offshore Kingdom of Thailand						
Exploratory	0.6	0.6	0.3	--	--	--
Total	45.1	4.3	27.8	1.6	23.4	2.7

</TABLE>

As of December 31, 1993, the Company was participating in the drilling of 4 gross (0.9 net) offshore domestic wells and 4 gross (2.7 net) onshore wells.

PRODUCTION AND SALES

The following table summarizes the Company's average daily production, net of all royalties, overriding royalties and other outstanding interests, for the periods indicated. Natural gas production refers only to marketable production of natural gas on an 'as sold' basis.

	1993	1992	1991
Production Sales:			
Natural Gas (Mcf per day)	91,700	105,200	104,200
Crude Oil and Condensate (Bbls per day)	9,851	8,699	7,108
Natural Gas Liquids (Bbls per day):			
Leasehold Ownership	1,538	1,037	609
Plant Ownership	140	144	54
Total	1,678	1,181	663

The following table shows the average sales prices received by the Company for its production and the average production (lifting) costs per unit of production during the periods indicated.

	1993	1992	1991
Sales Prices:			
Natural Gas (per Mcf)	$ 1.98	$ 1.75	$ 1.66
Crude Oil and Condensate (per Bbl)	$ 17.81	$ 20.17	$ 20.98
Natural Gas Liquids (per Bbl)	$ 11.90	$ 13.50	$ 14.21
Production (Lifting) Costs(a)			
Natural Gas, Crude Oil, Condensate and Natural Gas Liquids (per equivalent Mcf of Natural Gas)	$ 0.45	$ 0.43	$ 0.51

(a) Production costs were converted to common units of measure on the basis of relative energy content. Such production costs exclude all depletion and amortization associated with property and equipment.

The Company has entered into a crude oil swap agreement with another party in which it swapped the floating market price it received from purchasers of its crude oil for a fixed price of $16.00 per barrel on 1,000 Bbls per day of its production. The agreement expires July 31, 1994, but may be extended through January 31, 1995, at the other party's option.

EMPLOYEES

As of December 31, 1993, the Company had 102 employees. None of the Company's employees are presently represented by a union for collective bargaining purposes. The Company considers its relations with its employees to be excellent.

MANAGEMENT

Set forth below is certain information concerning the executive officers and directors of the Company as of February 15, 1994:

<TABLE>
<CAPTION>

NAME	AGE	POSITION	NUMBER OF YEARS OF SERVICE WITH COMPANY
<S>	<C>	<C>	<C>
Paul G. Van Wagenen	48	Chairman of the Board, President and Chief Executive Officer and Director	14
D. Stephen Slack	44	Senior Vice President -- Finance, Chief Financial Officer, Treasurer and Director	5
Tobin Armstrong	70	Director	16
Jack S. Blanton	66	Director	2

W. M. Brumley, Jr.-------------------	65	Director	23
John B. Carter, Jr.------------------	69	Director	16
William L. Fisher--------------------	61	Director	1
William E. Gipson--------------------	69	Director	23
Gerrit W. Gong-----------------------	40	Director	--
John Stuart Hunt---------------------	72	Director	10
Frederick A. Klingenstein------------	62	Director	6
Nicholas R. Petry--------------------	75	Director	12
Jack A. Vickers----------------------	68	Director	8
Kenneth R. Good----------------------	56	Senior Vice President -- Land and Budgets	16
Stuart P. Burbach--------------------	41	Vice President and Offshore Division Manager	6
Jerry A. Cooper----------------------	45	Vice President and Western Division Manager	14
Harvey L. Gold-----------------------	58	Vice President -- Engineering	16
Thomas E. Hart-----------------------	51	Vice President and Controller	16
R. Phillip Laney---------------------	53	Vice President and International Division Manager	16
John O. McCoy, Jr.-------------------	42	Vice President and Chief Administrative Officer	16
J. D. McGregor-----------------------	49	Vice President -- Sales	12
Sammie M. Shaw-----------------------	62	Vice President -- Operations	12
Ronald B. Manning--------------------	40	Associate General Counsel and Corporate Secretary	6

</TABLE>

Paul G. Van Wagenen became Chairman of the Board and Chief Executive Officer of the Company in March 1991. He had previously been elected to the office of President of the Company in October 1990. From 1986 to 1990, he served as Senior Vice President and General Counsel of the Company and was elected a Director of the Company in 1988. Mr. Van Wagenen joined the Company in 1979.

D. Stephen Slack has been Senior Vice President -- Finance of the Company since 1988 and a Director of the Company since 1989. Mr. Slack was, from 1982 until 1988, Vice President and regional manager of the Southwest Energy and Minerals Division of Chemical Bank of New York.

Tobin Armstrong has been engaged for more than five years in ranching. He became a Director of the Company in 1977.

Jack S. Blanton is President of Eddy Refining Company and Chairman of the Board of Houston Endowment, Inc. He became a Director of the Company in September 1991. Mr. Blanton also serves as a Director for Ashland Oil, Inc., Texas Commerce Bancshares, Inc., Southwestern Bell Corporation, Baker Hughes Incorporated and Burlington Northern, Inc.

W.M. Brumley, Jr., is a retired Senior Vice President -- Administration and Accounting of the Company and has been a member of the Board of Directors for more than five years. He became a Director of the Company in 1977.

John B. Carter, Jr., is Chairman of Houston National Bank. He was elected to his current term as a Director in 1990. From 1987 to 1990, Mr. Carter was an Advisory Director of the Company. Prior to 1987, Mr. Carter was Senior Vice President -- Finance of the Company, a Director and a member of the Executive Committee.

William L. Fisher is Director of the Bureau of Economic Geology and the Director of the Geology Foundation at the University of Texas at Austin. Dr. Fisher was formerly the Assistant Secretary -- Energy and Minerals of the U.S. Department of the Interior. Dr. Fisher has been a Director of the Company since February 1992. Dr. Fisher is also a Director of Diamond Shamrock, Inc.

William E. Gipson, formerly President and Chief Operating Officer of the Company, is Chairman of Gas Investment, Inc. He has been a Director of the Company since 1970.

Gerrit W. Gong is the Director for Asian Studies for the Center for Strategic and International Studies, in Washington, D.C., and has served in that capacity for more than the last five years. From 1987 to 1989 he also served as special assistant to two U.S. Ambassadors to China. He was elected a Director of the Company in May 1993.

John Stuart Hunt has been engaged for more than five years in managing his personal investments. He became a Director of the Company in 1983. Mr. Hunt is also a Director of Nomeco Oil & Gas Co. and SILCO, Inc.

Frederick A. Klingenstein has been Chairman of Klingenstein, Fields & Co., L.P., since January 1, 1989. He served as Chairman and Chief Executive Officer of Wertheim Schroder & Co., Incorporated from 1972 until 1986 and as Co-chairman and a Director of such firm from 1986 until 1988. Mr. Klingenstein has been a

Director of the Company since 1987.

Nicholas R. Petry is Chairman of the Board of Petry Company and Managing Partner of N.G. Petry Construction Company and Mill Iron Ranches. He has been engaged in such businesses for more than five years. He has served as a Director of the Company since 1981. Mr. Petry is also a Director of First Bank System, Inc.

Jack A. Vickers, as owner of the Vickers Companies, has been engaged for more than five years in managing his investments. He became a Director of the Company in 1985.

DESCRIPTION OF THE NOTES

The following description sets forth certain terms and provisions of the Notes. The Notes will be issued under an Indenture (the 'Indenture') to be entered into by the Company and Shawmut Bank Connecticut, National Association, as trustee (the 'Trustee'), prior to the issuance of any such Notes, the form of which is filed as an exhibit to the Registration Statement of which this Prospectus is a part.

The terms of the Notes include those stated in the Indenture and those made part of the Indenture by reference to the Trust Indenture Act of 1939, as amended (the 'Trust Indenture Act'). The Notes are subject to all such terms, and prospective purchasers of the Notes are referred to the Indenture and the Trust Indenture Act for a statement of those terms. The statements under this caption relating to the Notes are summaries and do not purport to be complete. Such summaries use

certain terms that are defined in the Indenture and are qualified in their entirety by express reference to the Indenture. The article and section references below are to articles and sections of the Indenture.

GENERAL

The Notes will be unsecured, subordinated obligations of the Company, will be limited in aggregate principal amount to $75,000,000, or up to $86,250,000 if the Underwriters exercise their over-allotment option in full, and will mature on March 15, 2004, unless previously converted or redeemed. (Section 301)

The Company will pay interest on the Notes semi-annually following the issuance thereof, at the rate per annum set forth on the cover of this Prospectus, on March 15th and September 15th of each year, commencing September 15, 1994. Interest on the Notes will be paid to the persons who are registered holders of the Notes (the 'Holders') at the close of business on the March 1st and September 1st next preceding such interest payment date. Interest will be computed on the basis of a 360-day year of twelve 30-day months. Principal (and premium, if any) and interest will be payable, and the Notes may be presented for conversion, exchange or registration of transfer, at the office or agency of the Company maintained for such purposes in New York, New York, or at such other office or agency as may be maintained by the Company for such purpose, except that payment of interest may, at the option of the Company, be made by check mailed on or before the due date to the address of the person entitled thereto as it appears on the security register. The Notes are to be issued only in registered form without coupons, in denominations of $1,000 or any integral multiple thereof. (Sections 203, 301, 302, 305, 307, 310 and 1002) The Company may maintain banking relationships in the ordinary course of business with the Trustee or its affiliates.

CONVERSION RIGHTS

The Holder of any Note will have the right, at the Holder's option, to convert the principal amount thereof (or any portion thereof that is an integral multiple of $1,000) into shares of Common Stock at any time prior to maturity, initially at the conversion price of $22.188 per share of Common Stock (subject to adjustments as described below), except that if a Note is called for redemption, the right to convert such called Note will terminate at the close of business on the Business Day (as such term is defined in the Indenture) immediately preceding the redemption date. No payment of interest and no adjustment in respect of dividends will be made upon the conversion of any Note, and the Holder will lose any right to payment of interest on the Notes surrendered for conversion; provided, however, that upon a call for redemption as described herein by the Company, accrued and unpaid interest to the redemption date shall be payable with respect to Notes that are converted after a notice of redemption has been mailed and prior to the redemption date. Notes surrendered for conversion during the period from the regular record date for an interest payment to the corresponding interest payment date (except Notes called for redemption as described herein) must be accompanied by payment of an amount equal to the interest thereon which the Holder is to receive on such interest payment date. No fractional shares will be issued upon conversion but, in lieu thereof, an appropriate amount will be paid in cash by the Company based on the reported last sale price for the shares of Common Stock on the day of conversion. (Sections 1301, 1303 and 1305)

The conversion price will be subject to adjustment in certain events, including: the issuance of stock as a dividend on the Common Stock; subdivisions or combinations of the Common Stock; the issuance to all holders of Common Stock of certain rights or warrants (expiring within 45 days after the record date for determining stockholders entitled to receive them) to subscribe for or purchase Common Stock at a price less than the current market price; or the distribution to substantially all Holders of Common Stock of evidences of indebtedness of the Company, cash (excluding quarterly cash dividends paid or to be paid on a regular basis), other assets or rights or warrants to subscribe for or purchase any securities (other than those referred to herein). No adjustment of the conversion price will be required to be made until cumulative adjustments amount to one percent or more of the

then current conversion price; however, any adjustment not made will be carried forward. (Section 1304)

The Company from time to time may decrease the conversion price by any amount for any period of at least 20 days, in which case the Company shall give at least 15 days notice to the Holders of the Notes of such decrease. The Company may also, at its option, make such decreases in the conversion rate as the Board of Directors of the Company deems advisable to avoid or diminish any income tax to holders of Common Stock resulting from any dividend or distribution of stock (or rights to acquire stock) or from any event treated as such for income tax purposes. (Section 1304)

Generally, no gain or loss should be recognized for federal income tax purposes upon the conversion of a Note into Common Stock (except to the extent of cash received in lieu of fractional shares or with respect to accrued interest). The Holder of a Note converted into Common Stock should generally have a carryover basis in such shares and the holding period for the Common Stock should include the holding period of the Note.

If the conversion price of the Notes is reduced (other than a reduction pursuant to the antidilution provisions of the Indenture, provided such provisions are deemed bona fide and reasonable under the circumstances), Holders of Notes would be treated as receiving a deemed distribution for federal income tax purposes that could, depending upon the then existing facts and circumstances relating to the Common Stock and Notes, be subject to income taxation. For example, a taxable deemed distribution is likely to occur if the conversion price of the Notes is reduced in connection with the payment of cash dividends to holders of Common Stock. Holders of Notes could therefore have taxable income as a result of an event pursuant to which they received no cash or property that could be used to pay the related income tax.

In case of any reclassification of the Common Stock, any consolidation of the Company with, or merger of the Company into, any other person, any merger of any person into the Company (other than a merger which does not result in any reclassification, conversion, exchange or cancellation of outstanding shares of Common Stock), any sale or other disposition of the assets of the Company substantially as an entirety or any compulsory share exchange whereby the Common Stock is converted into other securities, cash or other property, then provision shall be made such that the Holder of Notes then outstanding shall have the right thereafter, during the period such Notes shall be convertible, to convert such Notes only into the kind and amount of securities, cash and other property receivable upon such reclassification, consolidation, merger, sale, disposition or share exchange by a holder of the number of shares of Common Stock into which such Notes might have been converted immediately prior to such reclassification, consolidation, merger, sale, disposition or share exchange. (Section 1306)

SUBORDINATION

Payment of the principal of and premium, if any, and interest on the Notes will be subordinated in right of payment, as set forth in the Indenture, to the prior payment in full of all Senior Indebtedness of the Company when due in accordance with the terms thereof. Senior Indebtedness is defined in the Indenture as the principal of, premium, if any, and unpaid interest (including, without limitation, any interest accruing subsequent to the commencement of a case or other proceeding under any bankruptcy or other similar law with respect to the Company) on, and other obligations in respect of the following, whether outstanding at the date of the Indenture or thereafter incurred or created: (a) indebtedness of the Company for money borrowed (including purchase money obligations) evidenced by notes or other written obligations, (b) indebtedness of the Company evidenced by notes, debentures, bonds or other securities issued under the provisions of an indenture or similar instrument, (c) indebtedness secured by any mortgage, pledge, lien or other encumbrance existing on property which is owned or held by the Company subject to such mortgage, pledge or encumbrance, whether or not indebtedness secured thereby shall have been assumed by the Company, (d) obligations of the Company as lessee under capitalized leases and under leases of property made as part of

any sale and leaseback transactions, (e) obligations of the Company in respect of letters of credit issued for its account and 'swaps' of interest rates, commodity prices or currencies (and other interest rate, commodity price or foreign currency hedging agreements) to which the Company is a party, (f) indebtedness of others of any of the kinds described in the preceding clauses (a) through (e) assumed or guaranteed by the Company and (g) renewals, extensions and refundings of, and indebtedness and obligations of a successor person issued in exchange for or in replacement of, indebtedness or obligations of the kinds described in the preceding clauses (a) through (f); provided, however, that the following will not constitute Senior Indebtedness: (i) any indebtedness or obligation which by its terms refers explicitly to the Notes and states that such indebtedness or obligation shall not be senior in right of payment thereto, (ii) any indebtedness or obligation of the Company in respect of the Notes and (iii) any indebtedness or obligation of the Company to a subsidiary. (Sections 101 and 1401) Notwithstanding the foregoing, all indebtedness and obligations of the Company in respect of the 8% Debentures and the 10.25% Notes shall rank PARI PASSU with the Notes and shall not constitute Senior Indebtedness under the Indenture.

Upon the sale of the Notes and the application of the proceeds therefrom, approximately $19,000,000 aggregate principal amount of Senior Indebtedness is expected to be outstanding. See 'Use of Proceeds' and 'Capitalization.' There are no restrictions on the incurrence of indebtedness, including Senior Indebtedness, or other liabilities by the Company or its subsidiaries in the Indenture.

By reason of such subordination, in the event of dissolution, insolvency, bankruptcy or other similar proceeding, Holders of the Notes may recover less, ratably, than holders of Senior Indebtedness and other general creditors of the Company, and, upon any distribution of assets, the Holders of Notes will be required to pay over their share of such distribution to the holders of Senior Indebtedness until such Senior Indebtedness is paid in full. In addition, such subordination may affect the Company's obligation to make principal and interest payments with respect to the Notes if any Notes are declared due and payable prior to their stated maturity, or in the event of any default in the payment of principal of or premium, if any, or interest on any Senior Indebtedness, or in the payment of any commitment or other fees in respect thereof, or in the event of any default with respect to Senior Indebtedness that would permit acceleration of the maturity thereof, or in the event a judicial proceeding is pending with respect to any such Senior Indebtedness default. (Sections 1402, 1403 and 1404)

REDEMPTION AT OPTION OF COMPANY

The Notes are not redeemable prior to March 15, 1998. On and after March 15, 1998, the Notes are redeemable at the option of the Company, in whole or in part, at any time during the 12-month periods beginning March 15 of the years indicated at the following Redemption Prices (expressed as percentages of the principal amount):

YEAR	REDEMPTION PRICE
1998	103.30%
1999	102.75
2000	102.20
2001	101.65
2002	101.10
2003	100.55

together in each case with accrued and unpaid interest to the date fixed for redemption (subject to the right of Holders of record on the regular record date to receive interest due on an interest payment date). (Sections 203, 1101 and 1108)

Notes in any denomination equal to or larger than $1,000 may be redeemed in whole or in part in multiples of $1,000. On and after the redemption date, interest will cease to accrue on Notes or portions thereof called for redemption. (Sections 1104 and 1107)

Accrued and unpaid interest to the redemption date shall be payable with respect to Notes that are converted after a notice of redemption has been mailed and prior to the redemption date. (Section 1303)

Notice of redemption will be mailed at least 30 but not more than 60 days prior to the redemption date to each Holder of Notes to be redeemed at the address appearing in the security register maintained by the Company. If less than all the outstanding Notes are to be redeemed, the Trustee will select the Notes (or a portion thereof equal to $1,000 or any integral multiple thereof) to be redeemed by such method as the Trustee shall deem fair and appropriate. (Sections 1104 and 1105)

CERTAIN RIGHTS TO REQUIRE REPURCHASE OF NOTES

In the event of any Change in Control (as hereafter defined) of the Company which constitutes a Repurchase Event (as hereafter defined) occurring after the initial date of issuance of the Notes, each Holder of Notes will have the right, at the Holder's option, to require the Company to repurchase all or any part of the Holder's Notes on a date (the 'Repurchase Date') selected by the Company that is not more than 75 days after the date the Company gives notice of the Repurchase Event as described below at a price (the 'Repurchase Price') equal to 100% of the principal amount thereof, together with accrued and unpaid interest to the Repurchase Date. On or prior to the Repurchase Date, the Company shall deposit with the Trustee or a Paying Agent an amount of money sufficient to pay the Repurchase Price of the Notes which are to be repaid on or promptly following the Repurchase Date. (Sections 1201 and 1203)

On or before the 15th day after the occurrence of a Repurchase Event, the Company is obligated to mail to all Holders of Notes a notice of the occurrence of such Repurchase Event, Repurchase Date, the date by which the repurchase right must be exercised, the Repurchase Price and the procedures which the Holder must follow to exercise this right. To exercise the Repurchase Right, the Holder of Notes must deliver, on or before the close of business on the Business Day next preceding the Repurchase Date, written notice to the Company (or an agent designated by the Company for such purpose) and to the Trustee of the Holder's intent to exercise such rights, together with the Notes with respect to which the right is being exercised, duly endorsed for transfer. Such written notice will be irrevocable. (Section 1202)

A 'Change in Control' shall occur when: (i) the Company's assets are sold or otherwise disposed of substantially as an entirety to any person or related group of persons in any one transaction or a series of related transactions; (ii) there shall be consummated any consolidation or merger of the Company (A) in which the Company is not the continuing or surviving corporation (other than a consolidation or merger with a wholly owned subsidiary of the Company in which all shares of Common Stock outstanding immediately prior to the effectiveness thereof are changed into or exchanged for the same number of shares of common stock of such subsidiary) or (B) pursuant to which the Common Stock would be converted into cash, securities or other property, in each case, other than a consolidation or merger of the Company in which the holders of the Common Stock immediately prior to the consolidation or merger have, directly or indirectly, at least a majority of the common stock of the continuing or surviving corporation immediately after such consolidation or merger; or (iii) any person, or any persons acting together which would constitute a 'group' for purposes of Section 13(d) of the Exchange Act (other than the Company, any Subsidiary, any employee stock purchase plan, stock option plan or other stock incentive plan or program, retirement plan or automatic dividend reinvestment plan or any substantially similar plan of the Company or any Subsidiary or any person holding securities of the Company for or pursuant to the terms of any such employee benefit plan), together with any affiliates thereof, shall acquire beneficial ownership

(as defined in Rule 13d-3 under the Exchange Act) of at least 50% of the total voting power of all classes of capital stock of the Company entitled to vote generally in the election of directors of the Company. (Section 1206)

A Change in Control as described above shall constitute a Repurchase Event unless (i) the Current Market Price of the Common Stock on the date the Change in Control shall have occurred is at least equal to 105% of the conversion price of the Notes in effect immediately preceding the time of such Change in Control, or (ii) all of the consideration (excluding cash payments for fractional shares) in the transaction giving rise to such Change in Control to the holders of Common Stock consists of shares of common stock that are, or immediately upon issuance will be, listed on a national securities exchange or quoted on the NASDAQ National Market, and as a result of such transaction the Notes become convertible solely into such common stock, or (iii) the consideration in the transaction giving rise to such Change in Control to the holders of Common Stock consists of cash, securities that are, or immediately upon issuance will be, listed on a national securities exchange or quoted on the NASDAQ National Market, or a combination of cash and such securities and the aggregate fair market value of such consideration (which, in the case of such securities, shall be equal to the average of the daily Closing Prices of such securities during the ten consecutive trading days commencing with the sixth trading day following consummation of such transaction) is at least 105% of the conversion price of the Notes in effect on the date immediately preceding the closing date of such transaction. (Section 1206)

The right to require the Company to repurchase Notes as a result of the occurrence of a Repurchase Event could create an event of default under Senior Indebtedness of the Company, as a result of which any repurchase could, absent a waiver, be blocked by the subordination provisions of the Notes. See ' -- Subordination.' Failure by the Company to repurchase the Notes when required would result in an Event of Default (as herein defined) with respect to the Notes whether or not such repurchase were permitted by the subordination provisions. See '-- Defaults and Remedies.' The Company's ability to pay cash to the Holders of Notes upon a repurchase might be limited by certain financial covenants contained in the Company's Senior Indebtedness. In addition, there can be no assurance that the Company would have sufficient financial resources at the time of any such required purchase to enable it to purchase the Notes. (Sections 501 and 1404)

In the event a Repurchase Event occurs and the Holders exercise their rights to require the Company to repurchase Notes, the Company intends to comply with applicable tender offer rules under the Exchange Act, including Rules 13e-4 and 14e-1, as then in effect, with respect to any such purchase.

The foregoing provisions would not necessarily afford Holders of Notes protection in the event of highly leveraged or other transactions involving the Company that may adversely affect Holders. In addition, the foregoing provisions may discourage open market purchases of the Common Stock or a non-negotiated tender or exchange offer for such stock and accordingly, may limit a shareholder's ability to realize a premium over the market price of the Common Stock in connection with any such transaction.

CONSOLIDATION, MERGER AND SALE OF ASSETS

The Company, without the consent of any Holders of Notes, may consolidate or merge with or into any person, or convey, transfer, lease or otherwise dispose of its assets substantially as an entirety to any person, and any person may consolidate or merge with, or into, or transfer or lease its assets substantially as an entirety to, the Company, provided that (i) the person (if other than the Company) formed by such consolidation or into which the Company is merged or which acquires or leases the assets of the Company substantially as an entirety is organized and existing under the laws of the United States, any state thereof or the District of Columbia, and assumes the Company's obligations on the Notes and under the Indenture, (ii) after giving effect to such transaction, no Event of Default

and no event that, after notice or lapse of time or both, would become an Event of Default, shall have happened and be continuing and (iii) certain procedural conditions are met. (Article Eight)

DEFAULTS AND REMEDIES

The Indenture defines the following as Events of Default: default for 30 days in payment of interest on the Notes; default in payment of principal of or premium, if any, on the Notes; default for more than 10 days after a Repurchase Date in payment of the Repurchase Price; failure by the Company for 60 days after written notice to it to comply with any of its other covenants in the Indenture; default by the Company under any instrument or other evidence of indebtedness of the Company for money borrowed, or under any guarantee of payment by the Company for money borrowed, in an amount in excess of five percent of Consolidated Net Tangible Assets (as defined below), unless such default has been cured or waived; and certain events of bankruptcy, insolvency or reorganization relative to the Company. (Section 501)

'Consolidated Net Tangible Assets' means the total amount of assets of the Company and its Subsidiaries (less depreciation, depletion, valuation and other reserves) after deducting (i) all current liabilities, (ii) all goodwill, trade names, trademarks, patents, unamortized debt discount and expense and other like intangibles and (iii) minority interests in the equity of Subsidiaries. (Section 101)

If an Event of Default occurs and is continuing, the Trustee or Holders of at least 25% in aggregate principal amount of the Notes outstanding may declare the principal of the Notes to be due and payable immediately, but under certain conditions, such acceleration may be rescinded by the Holders of a majority in principal amount of the Notes then outstanding. (Sections 502 and 513).

Holders of Notes may not enforce the Indenture except as provided in such Indenture and except that, subject to any applicable subordination provisions, nothing shall prevent the Holders of Notes from enforcing payment of the principal of or premium, if any, or interest on, their Notes. The Trustee may refuse to enforce the Indenture unless it receives reasonable security or indemnity. Subject to certain limitations, Holders of a majority in aggregate principal amount of the Notes may direct the Trustee in its exercise of any trust or power under the Indenture. (Sections 507, 508, 512 and 603)

The Company will annually furnish the Trustee with an officers' certificate with respect to compliance with the terms of the Indenture. (Section 1005)

MODIFICATION

Modification and amendment of the Indenture may be effected by the Company and the Trustee with the consent of the Holders of a majority in aggregate principal amount of the Notes then outstanding under the Indenture, provided that no such modification or amendment may, without the consent of each Holder affected thereby, (i) reduce the rate or change the time or place for payment of principal, premium if any, or interest on any Note, (ii) reduce the principal of or rate of interest thereon, or the premium, if any, payable upon the redemption of, or change the fixed maturity of, any Note, (iii) make any Note payable in a currency other than U.S. dollars, (iv) impair the right to institute suit for the enforcement of any payment on or with respect to any such Note, (v) make any change that adversely affects the right convert any Note or (vi) reduce the amount of Notes whose Holders must consent to a modification or amendment or waive compliance with certain provisions of the Indenture. The Indenture also contains provisions permitting the Company and the Trustee to effect certain minor modifications to the Indenture not adversely affecting the rights of Holders of Notes in any material respect. (Sections 901 and 902)

GOVERNING LAW

The Notes and the Indenture provide that they are governed by the laws of the State of New York, without regard to the principles of conflicts of laws. (Section 112)

CONCERNING THE TRUSTEE

The Indenture contains certain limitations on the rights of the Trustee, should it become a creditor of the Company, to obtain payment of claims in certain cases, or to realize on certain property received in respect of any such claim as security or otherwise. The Trustee will be permitted to engage in other transactions with the Company; provided, however, if it acquires any conflicting interest and there exists a default with respect to the Notes, it must eliminate such conflict or resign. (Sections 608 and 613)

The Holders of a majority in aggregate principal amount of all outstanding Notes will have the right to direct the time, method and place of conducting any proceeding for exercising any remedy or power available to the Trustee under the Indenture, provided that such direction does not conflict with any rule of law or with the Indenture and would not involve the Trustee in personal liability or be unduly prejudicial to Holders of Notes not joining in such action (as determined by the Trustee in good faith). (Section 512)

In case a default or an Event of Default under the Indenture shall occur and be continuing and if it is known to the Trustee, the Trustee shall mail to each Holder of Notes notice of the default or Event of Default within 90 days after it occurs. Except in the case of a default or an Event of Default in payment of the principal of, premium, if any, or interest on any Note, the Trustee may withhold the notice if and so long as the Trustee in good faith determines that withholding the notice is in the interest of Holders of Notes. Subject to such provisions, when the Trustee incurs expenses or renders services after an Event of Default, the expenses and the compensation for the services are intended to constitute expenses of administration under any bankruptcy law. (Sections 602 and 607)

DESCRIPTION OF CAPITAL STOCK

AUTHORIZED AND OUTSTANDING CAPITAL STOCK

The authorized capital stock of the Company consists of 43,333,333 shares of Common Stock, of which 32,433,622 shares were issued and outstanding as of December 31, 1993; and 2,000,000 shares of preferred stock, par value $1 per share (the 'Preferred Stock'), of which no shares are issued and outstanding. The following summary description of the capital stock of the Company is qualified in its entirety by reference to the Company's Restated Certificate of Incorporation and Bylaws, copies of which are incorporated by reference as exhibits to the Registration Statement of which this Prospectus is a part.

COMMON STOCK

Subject to any preferential rights of any outstanding shares of Preferred Stock, the holders of the Common Stock are entitled to such dividends as may be declared from time to time in the discretion of the Board of Directors out of funds legally available therefor. See 'Price Range of Common Stock and Dividends.' Holders of Common Stock are entitled to share ratably in the net assets of the Company upon liquidation after payment or provision for all liabilities and any preferential liquidation rights of any Preferred Stock then outstanding. The rights of holders of Common Stock are subject to the rights of holders of any Preferred Stock which may be issued in the future. The holders of Common Stock have no preemptive rights to purchase additional shares of capital stock of the Company. Shares of Common Stock are not subject to any redemption or sinking fund provisions and are not convertible into any other securities of the Company.

Each share of Common Stock entitles the holder thereof to one vote at all meetings of the stockholders of the Company. The affirmative vote of the holders of at least 80% of the outstanding shares of Common Stock is required (i) to approve a merger, similar reorganization or certain other transactions involving the Company if the other party already owns or controls five percent of the outstanding Common Stock and the Board of Directors of the Company has not approved the transaction; (ii) to approve an amendment to the Company's Restated Certificate of Incorporation to alter or change the provision establishing a 'classified' Board of Directors of not less than three nor more than thirteen members, elected one-third annually; and (iii) to amend the foregoing and certain other provisions of the Restated Certificate of Incorporation.

The Company's capital stock has noncumulative voting rights, meaning that the holders of more than 50% of the voting power of the shares voting for the election of directors can elect 100% of the directors if they choose to do so. In such event, the holders of the remaining less-than-50% of the voting power of the shares voting for the election of directors will not be able to elect any directors.

PREFERRED STOCK

The Board of Directors of the Company is empowered, without approval of the stockholders, to cause shares of Preferred Stock to be issued in one or more series, with the number of shares of each series and the rights, preferences and limitations of each series to be determined by it. Among the specific matters that may be determined by the Board of Directors are the description and number of shares to constitute each series, the annual dividend rate, whether such dividends shall be cumulative, the time and price of redemption and the liquidation preference applicable to the series, whether the series will be subject to the operation of a 'sinking' or 'purchase' fund and, if so, the terms and provisions thereof, whether the shares of such series shall be convertible into shares of any other class or classes and the terms and provisions of such conversion rights, and the voting powers, if any, of the shares of such series. The Board of Directors may change the designation, rights, preferences, descriptions and terms of, and the number of shares in, any series of which no shares have theretofore been issued.

The issuance of one or more series of Preferred Stock could adversely affect the voting power of the holders of the Common Stock and could have the effect of discouraging or making more difficult any attempt by a person or group to obtain control of the Company.

TRANSFER AGENTS AND REGISTRARS

The Transfer Agents and Registrars for the Common Stock are Harris Trust Company of New York, New York, and Society National Bank, Houston, Texas.

DELAWARE LAW

The Company is subject to Section 203 of the Delaware General Corporation Law. In general, Section 203 prevents an interested stockholder (defined generally as any person owning 15% or more of the Company's outstanding voting stock) from engaging in a business combination (as defined herein) with a Delaware corporation for a period of three years from the date such person becomes an interested stockholder, unless (i) before such person became an interested stockholder, the board of directors of the corporation approved the transaction in which the interested stockholder became an interested stockholder or approved the business combination; (ii) upon consummation of the transaction that resulted in the interested stockholder's becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced (excluding stock held by directors who are also officers of the corporation and by employee stock plans that do not provide employees with the rights to determine confidentially whether the shares held subject to the plan will be tendered in a tender or exchange offer); or (iii) following the transaction in which such person became an interested stockholder, the business combination is approved by the board of directors of the corporation and authorized at a meeting of stockholders by the affirmative vote of the holders of at least two-thirds of the outstanding voting stock of the corporation not owned by the interested stockholder. Under Section 203, the restrictions described above also do not apply to certain business combinations proposed by an interested stockholder following the announcement or notification of one of certain extraordinary transactions involving the corporation and a person who had not been an interested stockholder during the previous three years or who became an interested stockholder with the approval of a majority of the corporation's directors, if such extraordinary transaction is approved or not opposed by a majority of the directors who were directors prior to any person becoming an interested stockholder during the previous three years or who were recommended for election or elected to succeed such directors by a majority of such directors. By restricting the ability of the Company to engage in business combinations with an interested person, the application of Section 203 to the Company may provide a barrier to hostile or unwanted takeovers.

UNDERWRITING

Subject to the terms and conditions set forth in a purchase agreement (the 'Purchase Agreement') among the Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Goldman, Sachs & Co. and PaineWebber Incorporated (the 'Underwriters'), the Company has agreed to sell to the Underwriters, and the Underwriters have severally agreed to purchase, the principal amount of Notes set forth opposite their respective names below (excluding the Notes subject to the Underwriters' overallotment option):

UNDERWRITER	PRINCIPAL AMOUNT
Merrill Lynch, Pierce, Fenner & Smith Incorporated	$25,000,000
Goldman, Sachs & Co.	25,000,000
PaineWebber Incorporated	25,000,000
Total	$75,000,000

The Purchase Agreement provides that, subject to the terms and conditions set forth therein, the Underwriters will be obligated to purchase the entire principal amount of the Notes offered hereby (other than those covered by the over-allotment option described herein) if any such Notes are purchased.

The Company has granted to the Underwriters an option, exercisable for 30 days from the date of this Prospectus, to purchase up to an additional $11,250,000 aggregate principal amount of the Notes at the initial public offering price, less the underwriting discount, set forth on the cover page of this Prospectus. The Underwriters may exercise such option solely to cover over-allotments, if any, in the sale of the Notes.

The Company has been advised by the several Underwriters that they propose to initially offer the Notes to the public at the public offering price set forth on the cover page of this Prospectus, and to certain dealers at such price less a concession not in excess of 1.5% of the principal amount thereof. The Underwriters may allow, and such dealers may reallow, a discount not in excess of .25% of the principal amount of the Notes to certain other dealers. After the initial public offering of the Notes, the public offering price, concession and discount may be changed by the Underwriters.

The Notes are a new issue for which there is currently no public market. The Company does not intend to apply for listing of the Notes on any securities exchange or for quotation on the NASDAQ National Market. The Company has been advised by the Underwriters that, following the completion of the Offering, each of the Underwriters presently intends to make a market in the Notes, as permitted by applicable law and regulations. The Underwriters are under no obligation, however, to do so and may discontinue any market-making activities at any time without notice. No assurance can be given as to the liquidity of the trading market for the Notes or that an active trading market for the Notes will develop. If an active public market does not develop, the market price and liquidity of the Notes may be adversely affected.

The Company has agreed that it will not offer, sell, contract to sell or otherwise dispose of, or register under the Securities Act on behalf of another person, any shares of Common Stock or preferred stock, any securities convertible into or exercisable or exchangeable for shares of Common Stock or any rights to acquire shares of Common Stock for a period of 90 days from the date of the Prospectus without the written consent of the Underwriters, except that the Company may, without such consent, (i) issue (A) shares of Common Stock issuable upon conversion of the Notes, (B) shares of Common Stock issuable upon conversion of the 10.25% Notes or the 8% Debentures, (C) shares of Common Stock issuable pursuant to options or similar rights granted to directors, officers or employees, and (D) shares of Common Stock issuable pursuant to any other employee benefit plans of the Company or (ii) grant options pursuant to existing stock option plans of the Company.

The Company has agreed to indemnify the Underwriters against certain liabilities, including liabilities arising under the Securities Act, and to contribute to payments the Underwriters may be required to make in respect of such liabilities.

LEGAL OPINIONS

Certain legal matters in connection with the Notes being offered hereby will be passed upon for the Company by Baker & Botts, L.L.P., Houston, Texas and for the Underwriters by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The consolidated financial statements and schedules of the Company included or incorporated by reference in this Prospectus and elsewhere in the Registration Statement have been audited by Arthur Andersen & Co., independent public accountants, as indicated in their reports with respect thereto, and are included herein in reliance upon the authority of said firm as experts in giving said reports.

The estimates of oil and gas reserves and discounted present values of estimated future net revenues therefrom set forth herein are extracted from the report of Ryder Scott attached as an exhibit to the Annual Report. Such information is included herein in reliance upon the authority of said firm as experts with respect to the matters contained in such report.

GLOSSARY OF OIL AND GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and in this Prospectus.

'Bcf' means billion cubic feet.

'Bbl' means barrel.

'Mcf' means thousand cubic feet.

'MMcf' means million cubic feet.

'MBbls' means thousand barrels.

'MMBbls' means million barrels.

'Deliverability' means a measure of the quantity of natural gas that a natural gas well can produce into a pipeline against a specific contractual back pressure.

'Development well' means a well drilled within areas already proved to be productive.

'Energy equivalent basis' means equating natural gas based on relative energy content, using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

'Exploratory well' means a well drilled to find commercially productive hydrocarbons in an unproved area.

'Gross' oil and gas wells or 'gross' acres are the total number of wells or acres in which the Company has an interest, without regard to the size of that interest.

'Net' oil and gas wells or 'net' acres are determined by multiplying gross wells or acres by the Company's working interest in those wells or acres.

'Net revenue interest' means the percentage of production to which the owner of a working interest is entitled. For example, the owner of a 100% working interest in a well burdened only by a typical landowner's royalty would have an 87.5% net revenue interest in that well.

'Proved Reserves' means estimated quantities of natural gas and crude oil, condensate and natural gas liquids, on a net revenue interest basis, that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing economic and operating conditions.

'Royalty' means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalty interests, which are usually reserved by a leasehold owner upon a transfer to a subsequent owner.

'Undeveloped acreage' means acreage on which wells have not been drilled or completed for commercial production, whether or not such acreage contains proved reserves.

'Working interest' means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. See the definitions of 'net revenue interest' and 'royalty' above. For example, the owner of 100% working interest in a lease burdened only by a typical landowner's royalty would be required to pay 100% of the costs of a well but would be entitled to retain 87.5% of the production. The remaining 12.5% would accrue to the royalty owners.

'Workover' means operations on a producing well to restore or increase production.

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REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders and Board of Directors of Pogo Producing Company:

We have audited the accompanying consolidated balance sheets of Pogo Producing Company (a Delaware corporation) and subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 1993. These financial statements and the schedules referred to below are the responsibility of Pogo's management. Our responsibility is to express an opinion on these financial statements and schedules 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 Pogo Producing Company and subsidiaries as of December 31, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN & CO.

Houston, Texas
February 8, 1994

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	YEAR ENDED DECEMBER 31, 1993	1992	1991
	(EXPRESSED IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		
Revenues:			
Oil and gas	$ 136,553	$ 139,128	$ 124,425
Interest on tax refund	2,322	--	--
Gains on sales	679	1,702	44
Total	139,554	140,830	124,469
Operating Costs and Expenses:			
Lease operating	26,633	25,842	28,192
General and administrative	14,550	13,129	14,555
Exploration	2,455	3,102	2,408
Dry hole and impairment	4,690	9,314	4,554
Depreciation, depletion and amortization	40,693	42,302	37,521
Total	89,021	93,689	87,230
Operating Income	50,533	47,141	37,239
Interest:			
Charges	(10,956)	(19,036)	(24,946)
Income	14	191	1,686
Capitalized	451	391	637
Income Before Taxes and Extraordinary Item	40,042	28,687	14,616
Income Tax Expense	(14,981)	(10,192)	(4,294)
Income Before Extraordinary Item	25,061	18,495	10,322
Extraordinary Gains on Purchase of Debt, net of tax	--	--	1,336
Net Income	$ 25,061	$ 18,495	$ 11,658
Primary and Fully Diluted Earnings per Common Share:			
Before extraordinary item	$0.76	$0.66	$0.37
Extraordinary item	--	--	0.05
Net income	$0.76	$0.66	$0.42

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	DECEMBER 31, 1993	1992
	(EXPRESSED IN THOUSANDS)	
ASSETS		
Current Assets:		
Cash and cash investments	$ 6,713	$ 5,037
Accounts receivable	18,480	22,652
Other receivables	10,123	4,173
Federal income taxes and interest receivable	3,320	--
Inventories	1,105	1,383
Other	727	367
Total current assets	40,468	33,612
Property and Equipment:		

Oil and gas, on the basis of successful efforts accounting		
Proved properties being amortized	817,218	869,192
Unproved properties and properties under development, not being amortized	6,465	5,962
Other, at cost	6,961	6,851
	830,644	882,005
Less -- accumulated depreciation, depletion, and amortization, including $4,452 and $4,032, respectively, applicable to other property	638,658	717,428
	191,986	164,577
Other	7,320	8,158
	$ 239,774	$ 206,347

LIABILITIES AND SHAREHOLDERS' EQUITY

Current Liabilities:		
Accounts payable	$ 8,307	$ 9,899
Other payables	22,955	5,541
Current portion of long-term debt	4,000	4,000
Current portion of production payment	--	10,517
Accrued interest payable	1,202	1,122
Accrued payroll and related benefits	1,005	942
Other	122	142
Total current liabilities	37,591	32,163
Long-Term Debt	130,539	129,260
Production Payment	--	14,337
Deferred Federal Income Tax	29,724	17,435
Deferred Credits	8,117	7,504
Total liabilities	205,971	200,699
Shareholders' Equity:		
Preferred stock, $1 par; 2,000,000 shares authorized	--	--
Common stock, $1 par; 43,333,333 shares authorized, 32,449,197 and 32,103,864 shares issued, respectively	32,449	32,104
Additional capital	125,919	122,846
Retained earnings (deficit)	(124,241)	(149,302)
Treasury stock, at cost	(324)	--
Total shareholders' equity	33,803	5,648
	$ 239,774	$ 206,347

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31, 1993	1992	1991
	(EXPRESSED IN THOUSANDS)		
Cash flows from operating activities:			
Cash received from customers	$ 141,012	$ 135,877	$ 125,029
Operating, exploration, and general and administrative expenses paid	(45,051)	(41,360)	(46,746)
Interest paid	(10,912)	(21,262)	(26,701)
Payment of royalties and related interest on FERC Order 94-A refunds	--	(4,872)	--
Federal income taxes paid	(2,800)	(1,500)	(2,900)
Federal income taxes and interest received	--	--	30,836
Settlement of natural gas sales contract	--	--	3,300
Proceeds of life insurance policy	--	--	2,568
Other	895	828	2,974

Net cash provided by operating activities	83,144	67,711	88,360
Cash flows from investing activities:			
Capital expenditures	(62,353)	(30,304)	(51,284)
Purchase of proved reserves	--	(8,924)	(5,077)
Proceeds from the sale of property and tubular stock	2,713	4,017	2,150
Net cash used in investing activities	(59,640)	(35,211)	(54,211)
Cash flows from financing activities:			
Net borrowings (payments) under revolving credit agreements	8,000	(1,000)	17,000
Principal payments of other long-term debt obligations	(7,000)	(54,000)	(42,000)
Principal payments of production payment obligation	(24,854)	(20,621)	(14,611)
Proceeds from exercise of stock options	2,026	703	123
Proceeds from issuance of common stock	--	43,313	--
Debt issue expenses paid	--	(1,100)	--
Increase in production payment	--	--	13,193
Purchase of 8% debentures, due 2005	--	--	(7,621)
Net cash used in financing activities	(21,828)	(32,705)	(33,916)
Net increase (decrease) in cash and cash investments	1,676	(205)	233
Cash and cash investments at the beginning of the year	5,037	5,242	5,009
Cash and cash investments at the end of the year	$ 6,713	$ 5,037	$ 5,242
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 25,061	$ 18,495	$ 11,658
Adjustments to reconcile net income to net cash provided by operating activities --			
Gains on purchase of 8% debentures, due 2005:			
Ordinary	--	--	(646)
Extraordinary, net of taxes	--	--	(1,336)
Gains on sales	(679)	(1,702)	(44)
Depreciation, depletion and amortization	40,693	42,302	37,521
Dry hole and impairment	4,690	9,314	4,554
Interest capitalized	(451)	(391)	(637)
Change in assets and liabilities:			
Decrease in United Kingdom tax escrow deposit	--	--	2,083
(Increase) decrease in accounts receivable	4,172	(1,191)	4,799
(Increase) decrease in federal income taxes and interest receivable	(3,320)	--	29,002
Increase in other current assets	(360)	(27)	(32)
(Increase) decrease in other assets	838	(3,515)	1,641
Increase (decrease) in accounts payable	(1,592)	733	(1,322)
Increase (decrease) in accrued interest payable	80	(2,480)	(1,342)
Increase (decrease) in accrued payroll and related benefits	63	(244)	375
Increase (decrease) in other current liabilities	(20)	(9)	62
Increase in deferred federal income taxes	13,356	8,669	1,268
Increase (decrease) in deferred credits	613	(2,243)	756
Net cash provided by operating activities	$ 83,144	$ 67,711	$ 88,360

The accompanying notes to consolidated financial statements are an integral part hereof.

<TABLE>

POGO PRODUCING COMPANY & SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

<CAPTION>

	SHARES OUTSTANDING	COMMON STOCK	ADDITIONAL CAPITAL	RETAINED EARNINGS (DEFICIT)	TREASURY STOCK	SHARE-HOLDERS' EQUITY (DEFICIT)
			(DOLLARS EXPRESSED IN THOUSANDS)			
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Balance at December 31, 1990---------	27,428,652	$ 27,428	$ 83,598	$ (179,455)	$ --	$ (68,429)
Net income---------------------------	--	--	--	11,658	--	11,658
Exercise of stock options------------	28,170	29	106	--	--	135
Balance at December 31, 1991---------	27,456,822	27,457	83,704	(167,797)	--	(56,636)
Net income---------------------------	--	--	--	18,495	--	18,495
Issuance of common stock-------------	4,500,000	4,500	38,368	--	--	42,868
Exercise of stock options------------	147,042	147	774	--	--	921
Balance at December 31, 1992---------	32,103,864	32,104	122,846	(149,302)	--	5,648
Net income---------------------------	--	--	--	25,061	--	25,061
Exercise of stock options------------	345,308	345	3,072	--	--	3,417
Acquisition of treasury stock at cost	(15,575)	--	--	--	(324)	(324)
Conversion of debenture--------------	25	--	1	--	--	1
Balance at December 31, 1993---------	32,433,622	$ 32,449	$ 125,919	$ (124,241)	$ (324)	$ 33,803

</TABLE>

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION --

The consolidated financial statements include the accounts of Pogo Producing Company and its wholly-owned subsidiaries (the 'Company'), after elimination of all significant intercompany transactions.

INVENTORIES --

Inventories consist primarily of tubular goods used in the Company's operations and are stated at the lower of average cost or market value.

INTEREST CAPITALIZED --

Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated.

EARNINGS PER SHARE --

Earnings per common and common equivalent share are based on weighted average shares of Common Stock outstanding assuming exercise of dilutive stock options. The 8% convertible subordinated debentures, due 2005 are common stock equivalents and were anti-dilutive in all periods presented. The 10.25% convertible subordinated notes, due 1999 are not common stock equivalents and were anti-dilutive in all periods presented. The weighted average number of common and common stock equivalent shares outstanding for primary earnings per share was 32,860,000, 27,929,000, and 27,611,000 in 1993, 1992, and 1991, respectively. The additional shares which would be assumed to be outstanding in the fully diluted calculation are not sufficient to change the earnings per share amounts reported in the primary calculation.

PRODUCTION IMBALANCES --

Owners of an oil and gas property often take more or less production from a property than entitled to based on their ownership percentages in the property. This results in a condition known in the industry as a production imbalance. The Company follows the 'take' (cash) method of accounting for production imbalances. Under this method, the Company recognizes revenues on production as it is taken and delivered to its purchasers. The Company's crude oil imbalances are not significant. At December 31, 1993, the Company had taken approximately 10,195 MMcf of natural gas less than it was entitled to based on its interest in those properties, and approximately 7,295 MMcf more than its entitlement on other properties placing the Company at year end in a net under-delivered position of approximately 2,900 MMcf of natural gas based on its working interest ownership in the properties.

OIL AND GAS ACTIVITIES AND DEPRECIATION, DEPLETION, AND AMORTIZATION --

The Company follows the successful efforts method of accounting for its oil and gas activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs are expensed as incurred. The provision for depreciation, depletion and amortization is determined on a field-by-field basis using the units of production method.

Other properties are depreciated on a straight-line method in amounts which in the opinion of management are adequate to allocate the cost of the properties over their estimated useful lives.

CONSOLIDATED STATEMENTS OF CASH FLOWS --

For the purpose of cash flows, the Company considers all highly liquid investments with a maturity date of three months or less to be cash equivalents. Significant transactions may occur which do not directly affect cash balances and as such will not be disclosed in the Consolidated Statement of Cash Flows. Certain such noncash transactions are disclosed in the Consolidated Statements of Shareholders' Equity relating to the acquisition of treasury stock in exchange for stock options exercised and the conversion of a debenture into Common Stock. In addition, the Company exchanged its working interest in thirteen Gulf of Mexico oil and gas properties for an increased working interest in five other Gulf of Mexico oil and gas properties in a noncash 'like kind' exchange. The oil and gas property and accumulated depreciation, depletion and amortization accounts as reflected in the Consolidated Balance Sheets have been adjusted to reflect the appropriate amounts to record the working interests acquired and disposed of. The oil and gas reserves acquired and disposed of are reflected as purchases and sales in the roll forward 'Estimates of Proved Reserves' included in the 'Unaudited Supplementary Financial Data' included elsewhere herein.

COMMITMENTS AND CONTINGENCIES --

The Company's rent expense was $868,000, $808,000, and $1,069,000 in 1993, 1992, and 1991, respectively. The Company has lease commitments for office space of $809,000 per year in each year for 1994 through 1997 and $777,000 in 1998.

(2) INCOME TAXES

The components of federal income tax expense (benefit) for each of the three years in the period ended December 31, 1993, are as follows (expressed in thousands):

	1993	1992	1991
United States			
Current--------------------------	$ 2,800	$ 1,500	$ 2,900
Deferred (a)---------------------	12,360	8,672	1,125
Foreign			
Current--------------------------	(179)	20	269
Total------------------------	$ 14,981	$ 10,192	$ 4,294

(a) Excludes $688,000 of deferred taxes on a $2,024,000 extraordinary item in 1991.

Total federal income tax expense (benefit) for each of the three years in the period ended December 31, 1993, differs from the amounts computed by applying the statutory federal income tax rate to income before taxes as follows (expressed as a percent of pretax income):

	1993	1992	1991
Federal statutory income tax rate----	35.0%	34.0%	34.0%
Increases (reductions) resulting from:			
Statutory depletion in excess of tax basis----------------------	(0.4)	(0.1)	(0.9)
Foreign taxes--------------------	2.9	1.4	1.8
Life insurance loan proceeds-----	--	--	(5.9)
Other----------------------------	--	0.2	0.4
	37.5%	35.5%	29.4%

POGO PRODUCING COMPANY & SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

The deferred federal income tax provision is the result of the difference between deferred tax liabilities determined at each balance sheet date. The deferred tax liabilities are determined by applying current tax laws to temporary differences in the recognition of revenue and expense for tax and financial purposes. Temporary differences arise primarily from the amortization of productive intangible drilling costs which are capitalized and amortized for financial statement purposes but are deducted for income tax purposes and differences in depreciation rates for tangible assets for financial and tax reporting purposes.

As of December 31, 1993, the Company has general business credits of approximately $1,400,000, which can be used to reduce future income taxes. In addition, the Company has alternative minimum tax credits of approximately $4,235,000 which can be used to reduce future regular income taxes payable.

(3) LONG-TERM DEBT

Long-term debt and the amount due within one year at December 31, 1993 and 1992, consists of the following (dollars expressed in thousands):

	DECEMBER 31, 1993	DECEMBER 31, 1992
Senior debt --		
Bank revolving credit agreements debt:		
Prime rate loans	$ 27,000	$ 9,000
LIBO Rate loans	40,000	50,000
Certificate of deposit rate loans	--	--
Total senior debt	67,000	59,000
Subordinated debt --		
10.25% Convertible subordinated notes, due 1999, $4,000 annual sinking fund requirement	24,000	28,000
8% Convertible subordinated debentures, due 2005, $1,540 sinking fund requirement in 1995 and a $3,000 annual sinking fund requirement thereafter	43,539	46,260
Total subordinated debt	67,539	74,260
Total debt	134,539	133,260
Amount due within one year --		
Current portion of long-term debt, consisting of sinking fund requirement on 10.25% notes	(4,000)	(4,000)
Long-term debt	$ 130,539	$ 129,260

The bank revolving credit agreement entered into in December 1993, extends to the Company a $100,000,000 revolving/term credit facility which will be fully revolving until June 29, 1996 and will convert to a term loan with eight quarterly installments commencing July 31, 1996. The amount that may be borrowed under the facility may not exceed a borrowing base, determined semiannually by the lenders based on the discounted present value of the Company's oil and gas reserves and the provisions of the agreement. The borrowing base currently exceeds $100,000,000. The agreement provides that total debt and total debt for borrowed money, as defined, may not exceed $230,000,000 and $200,000,000, respectively. The facility is governed by various financial covenants including the maintenance of positive working capital (excluding current maturities of debt), a fixed charge ratio, as defined, of 1.7 or greater, a $10,000,000 limit on other senior debt, and a $10,000,000 limit on prepayment (without refinancing) of subordinated debt in any one year and $20,000,000 in total through July 31, 1996. Upon the occurrence of an event of default or certain other specified events, the banks would be entitled to a security interest in the borrowing base properties, which constitute substantially all of the Company's domestic oil and gas properties. Borrowings under the facility bear interest at Base (Prime) rate plus 1/4%, a certificate of deposit rate plus 1 7/8%, or LIBOR plus 1 3/4%, at the Company's option. A commitment fee of 1/2 of 1% per annum of the unborrowed amount under the facility is also due. The Company incurred commitment fees of $149,000 in 1993, $80,000 in 1992, and $132,000 in 1991 under this and prior revolving credit agreements.

The 10.25% convertible notes are convertible into Common Stock at $23.95 per share subject to adjustment under certain circumstances, including stock splits. The convertible debentures are redeemable at the option of the Company at 103.7% through April 1, 1994, at 102.95% through April 1, 1995, and decreasing percentages thereafter, under certain market conditions, and are subject to mandatory annual sinking fund requirements of $4,000,000 which commenced April 1, 1990. The sinking fund requirements will be sufficient to retire 90% of the issue prior to maturity.

The 8% convertible debentures are convertible into Common Stock at $39.50 per share subject to adjustment under certain circumstances, including stock splits. These convertible debentures are redeemable at the option of the Company at 102.8% through December 30, 1994, and decreasing percentages thereafter, and are subject to mandatory annual sinking fund requirements of $3,000,000 which commenced December 31, 1990. Such requirements will be sufficient to retire 75% of the issue prior to maturity. To date, the Company has purchased $13,740,000 principal amount of the bonds at less than face value resulting in ordinary gains of $646,000 and $902,000 in 1991 and 1990, respectively, on the bonds purchased in satisfaction of sinking fund requirements in those years, and a $1,336,000 extraordinary gain (net of taxes) in 1991 on the bonds purchased in excess of current sinking fund requirements. The Company currently has $4,460,000 face amount of the bonds purchased in excess of current sinking fund requirements which may be tendered in satisfaction of future sinking fund requirements. The Company elected to make the December 31, 1993 sinking fund payment in cash.

Current maturities and sinking fund requirements during the next five years in connection with the above long-term debt are $4,000,000 in 1994, $5,540,000 in 1995, $27,100,000 in 1996, $40,500,000 in 1997 and $20,400,000 in 1998. Included in the current maturities reflected above are $20,100,000 in 1996, $33,500,000 in 1997, and $13,400,000 in 1998 relative to bank debt. The Company has established a history of refinancing its bank debt before scheduled maturities and expects to do so again before the amortization of bank debt commences in 1996.

In 1993, the Company entered into interest rate swap agreements on $15,000,000 of its bank debt, $5,000,000 of which terminated in January, 1994 and $10,000,000 of which terminates in July, 1994. The swap agreements effectively change the interest rates from variable to fixed rates which average 5.78% on the $15,000,000.

(4) SALES TO MAJOR CUSTOMERS

The Company is an oil and gas exploration and production company that until recently sold its production to relatively few customers. As a result of recent changes in the natural gas industry, the Company, like many other producers, now sells its natural gas to numerous customers on a month-to-month basis. The Company no longer has a significant amount of its natural gas reserves committed to long-term (multiple year) contracts at higher than prevailing market prices. Sales to the following customers exceeded 10 percent of oil and gas revenues during the years indicated (expressed in thousands):

	1993	1992	1991
Scurlock Oil Company-----------------	$ 38,510	$ 39,729	$ 38,554
United Gas Pipeline Company----------	$ --	$ --	$ 21,074
Enron Corp---------------------------	$ 16,437	$ --	$ --

(5) EMPLOYEE BENEFITS

A total of 2,353,069 shares of Common Stock are reserved for issuance to key employees and non-employee directors under the Company's stock option plans. The stock option plans authorize the granting of options at prices equivalent to the market value at the date of grant. Options generally become exercisable in three annual installments commencing one year after the date granted and, if not exercised, expire 10 years from the date of grant. At January 1, 1993, 1,544,484 shares were issuable under stock options outstanding. Options for 291,500 shares were granted during 1993 at prices ranging from $15.13 to $19.00 per share. During 1993, 345,308 options were exercised at prices ranging from $4.38 to $16.25 per share and no options were cancelled. At December 31, 1993, options to purchase 1,490,676 shares were outstanding (1,098,815 were exercisable) at prices ranging from $4.38 to $19.00.

The Company has a tax-advantaged savings plan in which all salaried employees may participate. Under such plan, a participating employee may allocate up to 10% of his salary, and the Company makes matching contributions of up to 6% thereof. Funds contributed by the employee and the matching funds contributed by the Company are held in trust by a bank trustee in six separate funds. Funds contributed by the employee and earnings and accretions thereon may be used to purchase shares of Common Stock, invest in a money market fund or invest in four stock, bond, or blended stock and bond mutual funds according to instructions from the employee. Matching funds contributed to the savings plan by the Company are invested only in Common Stock. The Company contributed $125,000 to the savings plan in 1993, $288,000 in 1992, and $265,000 in 1991.

A trusteed retirement plan has been adopted by the Company for its salaried employees. The benefits are based on years of service and the employee's average compensation for five consecutive years within the final ten years of service which produce the highest average compensation. The Company makes annual contributions to the plan in the amount of retirement plan cost accrued or the maximum amount which can be deducted for federal income tax purposes. The following table sets forth the plan's funded status (in thousands of dollars) as of December 31, 1993, 1992, and 1991.

	1993	1992	1991
Actuarial present value (discounted at 7 1/2, 8 1/4, and 8 1/2%, respectively) of benefit obligations:			
Accumulated benefit obligations --			
Vested	$ 4,019	$ 3,120	$ 2,997
Nonvested	717	701	657
Total accumulated benefit obligations	4,736	3,821	3,654
Projected salary increases (escalated at 6%) and other changes	1,500	2,653	2,441
Projected benefit obligations for service rendered to date	6,236	6,474	6,095
Plan assets at fair value, primarily listed securities with an expected long-term rate of return of 8 1/4%	13,481	13,830	13,505
Plan assets in excess of projected benefit obligations	7,245	7,356	7,410
Unrecognized:			
Net overfunding being recognized over 15 years	(750)	(853)	(957)
Net gain arising from the difference between actual experience and that assumed	(3,209)	(3,956)	(4,438)
Prior service cost	(473)	(41)	(45)
Accrued retirement plan asset	$ 2,813	$ 2,506	$ 1,970

(TABLE CONTINUED ON FOLLOWING PAGE)

	1993	1992	1991
Retirement plan cost (benefit) for 1993, 1992, and 1991 included the following components:			
Service cost, benefits accruing each year with proration for future salary increases	$ 611	$ 514	$ 501
Interest cost on projected benefit obligations	524	451	508
Actual return on plan assets	(1,164)	(1,141)	(3,882)
Net amortization and deferral	(278)	(360)	2,853
Accrued retirement plan cost (benefit)	$ (307)	$ (536)	$ (20)

Effective January 1, 1992, the Company adopted the provisions of the Statement of Financial Accounting Standards No. 106, 'Employers' Accounting for Postretirement Benefits Other Than Pensions.' The Company currently provides full medical benefits to its retired employees and dependents. For current employees, the Company assumes all or a portion of postretirement medical and term life insurance costs based on the employee's age and length of service with the Company. The postretirement medical plan has no assets and is currently funded by the Company on a pay-as-you-go basis.

The following is an analysis (in thousands of dollars) of the annual expense and activity in the deferred cost and benefits obligation accounts for 1992 and 1993. The computation assumes that future increases in medical costs will trend down from 13% to 7% per year over the next 12 years for purposes of estimating future costs. The medical cost trend rate assumption has a significant effect on the amounts reported. Increasing the assumed medical cost trend rate by one percent in each year would increase the aggregate of service and interest cost components of net periodic postretirement benefits cost for 1993 by $164,000 and the accumulated postretirement benefits obligation as of December 31, 1993 by $1,171,000.

<TABLE>
<CAPTION>

<S>	ANNUAL EXPENSE <C>	DEFERRED COSTS <C>	BENEFITS OBLIGATION <C>
Transition obligation at January 1, 1992		$ 4,263	$ (4,263)
Amortization of transition cost over 14 years representing the average remaining service period of eligible employees	$ 305	(305)	305
Service cost, including interest	303		
Interest cost on transition obligation	362		
1992 expense	$ 970		(970)
Current benefits paid			170
Balance at December 31, 1992		3,958	(4,758)
Amortization of transition costs over 14 years	$ 305	(305)	305
Service cost, including interest	368		
Interest cost on transition obligation	407		
1993 expense	$ 1,080		(1,080)
Current benefits paid			246
Unrecognized loss			(1,400)
Balance at December 31, 1993		$ 3,653	
Plan assets at fair value			--
Funded status at December 31, 1993 (discounted at 7 1/2%)			$ (6,687)

</TABLE>

The accumulated postretirement benefit obligation (in thousands of dollars) at December 31, 1993 is attributable to the following groups:

Retirees and beneficiaries	$ 2,739
Dependents of retirees	1,188
Fully eligible active employees	577
Active employees, not fully eligible	2,183
	$ 6,687

(6) FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value.

CASH AND CASH INVESTMENTS

The carrying value approximates fair value because of the short maturity of these investments.

DEBT

INSTRUMENT	BASIS OF FAIR VALUE ESTIMATE
Bank revolving credit agreement debt	Fair value is carrying value based on recent 1993 renegotiation with banks
10.25% Convertible subordinated notes, due 1999	Fair value is 103.7% of carrying value based on the redemption premium at December 31, 1993
8% Convertible subordinated debentures, due 2005	Fair value is 99.5% of carrying value based on the quoted market price for this publicly traded debt at December 31, 1993

The estimated fair value of the Company's financial instruments (in thousands of dollars) are as follows:

	CARRYING VALUE	FAIR VALUE
Cash and cash investments------------	$ 6,713	$ 6,713
Debt----------------------------------	(134,539)	(135,209)

UNAUDITED SUPPLEMENTARY FINANCIAL DATA

OIL AND GAS PRODUCING ACTIVITIES

The results of operations from oil and gas producing activities excludes non-oil and gas revenues, general and administrative expenses, interest charges, interest income and interest capitalized. United States income tax expense was determined by applying the statutory rates to pretax operating results with adjustments for permanent differences. Kingdom of Thailand tax expense was determined by applying the statutory tax rate to Thailand taxable income.

	TOTAL	UNITED STATES	KINGDOM OF THAILAND
	(EXPRESSED IN THOUSANDS)		
		1993	
Oil and gas revenues-----------------	$ 136,553	$ 136,525	$ 28
Lease operating expense--------------	(26,633)	(26,633)	--
Exploration expense------------------	(2,455)	(1,060)	(1,395)
Dry hole and impairment expense------	(4,690)	(2,737)	(1,953)
Depreciation, depletion and amortization expense---------------	(40,224)	(40,193)	(31)
Pretax operating results-------------	62,551	65,902	(3,351)
Income tax (expense) benefit---------	(22,712)	(22,891)	179
Operating results--------------------	$ 39,839	$ 43,011	$ (3,172)
		1992	
Oil and gas revenues-----------------	$ 139,128	$ 139,128	$ --
Lease operating expense--------------	(25,842)	(25,842)	--
Exploration expense------------------	(3,102)	(1,876)	(1,226)
Dry hole and impairment expense------	(9,314)	(9,314)	--
Depreciation, depletion and amortization expense---------------	(41,849)	(41,834)	(15)
Pretax operating results-------------	59,021	60,262	(1,241)
Income tax expense-------------------	(20,510)	(20,490)	(20)
Operating results--------------------	$ 38,511	$ 39,772	$ (1,261)
		1991	
Oil and gas revenues-----------------	$ 124,425	$ 124,425	$ --
Lease operating expense--------------	(28,192)	(28,192)	--
Exploration expense------------------	(2,408)	(2,261)	(147)
Dry hole and impairment expense------	(4,554)	(4,554)	--
Depreciation, depletion and amortization expense---------------	(36,970)	(36,965)	(5)
Pretax operating results-------------	52,301	52,453	(152)
Income tax expense-------------------	(17,725)	(17,698)	(27)
Operating results--------------------	$ 34,576	$ 34,755	$ (179)

The following table sets forth Pogo's capitalized costs (expressed in thousands) incurred for oil and gas producing activities during the years indicated.

	1993	1992	1991
Capitalized costs incurred:			
Property acquisition (United States)------------------------	$ 1,520	$ 11,578	$ 7,697
Exploration --			
United States----------------	8,267	3,865	3,546
Kingdom of Thailand----------	4,583	1,412	--
Development --			
United States----------------	57,648	20,717	37,025
Kingdom of Thailand----------	--	--	--
Interest capitalized (United States)------------------------	451	391	637
	$ 72,469	$ 37,963	$ 48,905
Provision for depreciation, depletion, and amortization:			
United States----------------	$ 40,193	$ 41,834	$ 36,965
Kingdom of Thailand----------	31	15	5
	$ 40,224	$ 41,849	$ 36,970

UNAUDITED SUPPLEMENTARY FINANCIAL DATA -- (CONTINUED)

The following information regarding estimates of the Company's proved oil and gas reserves, which are located offshore in United States waters of the Gulf of Mexico, onshore in the United States and offshore in the Kingdom of Thailand is based on reports prepared by Ryder Scott Company Petroleum Engineers. Their summary report dated January 28, 1994 is set forth as an exhibit to the Annual Report and includes definitions and assumptions as set forth therein and which serve as the basis for the discussion under the caption 'Business and Properties-- Reserves.'Such definitions and assumptions should be referred to in connection with the following information.

ESTIMATES OF PROVED RESERVES

	OIL, CONDENSATE AND NATURAL GAS LIQUIDS (BBLS.)	NATURAL GAS (MMCF)
Proved reserves (located in the United States) as of December 31, 1990	19,090,376	217,500
Revisions of previous estimates	782,707	3,531
Extensions, discoveries, and other additions	1,612,983	16,157
Purchase of properties	263,495	4,913
Sales of properties	(5)	(4)
Estimated 1991 production	(2,931,465)	(39,362)
Proved reserves (located in the United States) as of December 31, 1991	18,818,091	202,735
Revisions of previous estimates	1,721,385	20,284
Extensions, discoveries, and other additions (including 2,576,907 barrels and 10,668 MMcf located in the Kingdom of Thailand)	5,486,273	19,126
Purchase of properties	335,750	10,237
Sales of properties	(194,606)	(4,733)
Estimated 1992 production	(3,611,105)	(40,581)
Proved reserves (located in the United States except for 2,576,907 barrels and 10,668 MMcf located in the Kingdom of Thailand) as of December 31, 1992	22,555,788	207,068
Revisions of previous estimates	342,022	1,148
Extensions, discoveries, and other additions (including 2,847,906 barrels and 22,806 MMcf located in the Kingdom of Thailand)	9,764,408	55,626
Purchase of properties	182,610	13,192
Sales of properties	(356,514)	(11,849)
Estimated 1993 production	(4,219,873)	(32,319)
Proved reserves (located in the United States except for 5,424,813 barrels and 33,474 MMcf located in the Kingdom of Thailand) as of December 31, 1993	28,268,441	232,866
Proved developed reserves (located in the United States) as of:		
December 31, 1990	17,841,751	202,471
December 31, 1991	17,549,830	188,090
December 31, 1992	18,798,149	175,523
December 31, 1993	20,976,194	183,139

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES

	1993		
	TOTAL	UNITED	KINGDOM OF

	COMPANY	STATES	THAILAND
	(EXPRESSED IN THOUSANDS)		
Future gross revenues	$ 869,783	$ 744,201	$ 125,582
Future production costs:			
Lease operating expense	(186,464)	(158,934)	(27,530)
Future development and abandonment costs	(133,258)	(79,735)	(53,523)
Future net cash flows before income taxes	550,061	505,532	44,529
Discount at 10% per annum	(146,221)	(118,858)	(27,363)
Discounted future net cash flow before income taxes	403,840	386,674	17,166
Future income taxes, net of discount at 10% per annum	(103,580)	(98,788)	(4,792)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 300,260	$ 287,886	$ 12,374
		1992	
Future gross revenues	$ 856,238	$ 791,865	$ 64,373
Future production costs:			
Lease operating expense	(179,721)	(173,355)	(6,366)
Future development and abandonment costs	(105,843)	(80,887)	(24,956)
Future net cash flows before income taxes	570,674	537,623	33,051
Discount at 10% per annum	(165,573)	(146,730)	(18,843)
Discounted future net cash flow before income taxes	405,101	390,893	14,208
Future income taxes, net of discount at 10% per annum	(97,444)	(91,848)	(5,596)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 307,657	$ 299,045	$ 8,612
		1991	
Future gross revenues	$ 725,360	$ 725,360	$ --
Future production costs:			
Lease operating expense	(163,262)	(163,262)	--
Future development and abandonment costs	(67,671)	(67,671)	--
Future net cash flows before income taxes	494,427	494,427	--
Discount at 10% per annum	(144,673)	(144,673)	--
Discounted future net cash flow before income taxes	349,754	349,754	--
Future income taxes, net of discount at 10% per annum	(76,423)	(76,423)	--
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 273,331	$ 273,331	$ --

The standardized measure of discounted future net cash flows from the production of proved reserves is developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods in which they are expected to be produced based on year end economic conditions.

2. The estimated future gross revenues from proved reserves are priced on the basis of year end prices, except in those instances where fixed and determinable natural gas price escalations are covered by contracts.

3. The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year end cost estimates, and the estimated effect of future income taxes.

The standardized measure of discounted future net cash flows does not purport to present the fair market value of Pogo's oil and gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following are the principal sources of change in the standardized measure of discounted future net cash flows. All amounts are related to changes in reserves located in the United States unless otherwise noted.

	YEAR ENDED DECEMBER 31, 1993		
	TOTAL COMPANY	UNITED STATES	KINGDOM OF THAILAND
	(EXPRESSED IN THOUSANDS)		
Beginning balance	$ 307,657	$ 299,045	$ 8,612
Revisions to prior years' proved reserves:			
Net changes in prices and production costs	(41,775)	(34,842)	(6,933)
Net changes due to revisions in quantity estimates	4,066	4,066	--
Net changes in estimates of future development costs	662	(871)	1,533
Accretion of discount	40,510	39,089	1,421
Changes in production rate	5,134	6,728	(1,594)
Other	2,278	3,935	(1,657)
Total revisions	10,875	18,105	(7,230)
New field discoveries and extensions, net of future production and development costs:	39,247	29,059	10,188
Purchases of properties	22,516	22,516	--
Sales of properties	(19,633)	(19,633)	--
Sales of oil and gas produced, net of production costs	(110,870)	(110,870)	--
Previously estimated development costs incurred	56,604	56,604	--
Net change in income taxes	(6,136)	(6,940)	804
Net change in standardized measure of discounted future net cash flows	(7,397)	(11,159)	3,762
Ending balance	$ 300,260	$ 287,886	$ 12,374

STANDARDIZED MEASURE OF DISCOUNTED FUTURE
NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES -- (CONTINUED)

	YEAR ENDED DECEMBER 31,	
	1992	1991
	(EXPRESSED IN THOUSANDS)	
Beginning balance	$ 273,331	$ 400,937
Revisions to prior years' proved reserves:		
Net changes in prices and production costs	38,348	(174,464)
Net changes due to revisions in quantity estimates	42,829	9,940
Net changes in estimates of future development costs	(21,015)	(28,740)
Accretion of discount	34,975	52,517
Changes in production rate	(5,733)	(6,518)
Other	6,607	(7,404)
Total revisions	96,011	(154,669)
New field discoveries and extensions, net of future production and development costs:		
United States	29,552	28,286
Kingdom of Thailand	14,208	--
Purchases of properties	13,870	6,827
Sales of properties	(7,430)	(7)
Sales of oil and gas produced, net of production costs	(111,581)	(92,895)
Previously estimated development costs incurred	20,717	37,039
Net change in income taxes:		
United States	(15,425)	47,813
Kingdom of Thailand	(5,596)	--
Net change in		

standardized measure of discounted future net cash flows-------------	34,326	(127,606)
Ending balance-----------------------	$ 307,657	$ 273,331

</TABLE>

QUARTERLY RESULTS

Summaries of Pogo's results of operations by quarter for the years 1993 and 1992 are as follows:

<TABLE>
<CAPTION>

	QUARTER ENDED MAR. 31	JUNE 30	SEPT. 30	DEC. 31
	(EXPRESSED IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)			
<S>	<C>	<C>	<C>	<C>
1993				
Revenues-----------------------------	$ 34,681	$ 34,533	$ 37,210	$ 33,130
Gross profit(a)----------------------	$ 17,331	$ 15,391	$ 17,903	$ 14,458
Net income---------------------------	$ 7,160	$ 5,596	$ 7,161	$ 5,144
Earnings per share (primary and fully diluted)--------	$ 0.22	$ 0.17	$ 0.22	$ 0.16
1992				
Revenues-----------------------------	$ 28,347	$ 34,072	$ 34,907	$ 43,504
Gross profit(a)----------------------	$ 7,147	$ 12,646	$ 16,165	$ 24,312
Net income (loss)--------------------	$ (1,216)	$ 3,276	$ 5,535	$ 10,900
Earnings (loss) per share (primary and fully diluted)--------	$ (0.04)	$ 0.12	$ 0.20	$ 0.38

(a) Represents revenues less lease operating, exploration, dry hole and impairment, and depreciation, depletion and amortization expenses.

</TABLE>

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$75,000,000

LOGO

POGO PRODUCING COMPANY
5 1/2% CONVERTIBLE
SUBORDINATED NOTES DUE 2004

PROSPECTUS

MERRILL LYNCH & CO.
GOLDMAN, SACHS & CO.
PAINEWEBBER INCORPORATED

MARCH 16, 1994