SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 1998

Commission File Number 0-25192

CALLON PETROLEUM COMPANY
(Exact name of Registrant as specified in its charter)

Delaware	64-0844345
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

200 North Canal Street (601) 442-1601
Natchez, Mississippi 39120 (Registrant's telephone number
(Address of Principal Executive including area code)
Offices)(Zip Code)

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

Title of each class	Name of exchange on which registered
Convertible Exchangeable Preferred Stock, Series A, Par Value $.01 Per Share	New York Stock Exchange
Common Stock, Par Value $.01 Per Share	New York Stock Exchange

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

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

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

The aggregate market value of the voting stock held by nonaffiliates of the registrant was approximately $60,644,981, as of March 24, 1999 (based on the last reported sale price of such stock on the New York Stock Exchange).

As of March 24, 1999, there were 8,543,722 shares of the Registrant's Common Stock, par value $.01 per share, outstanding.

Document incorporated by reference: Portions of the definitive Proxy Statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 1998) relating to the Annual Meeting of Stockholders to be held on April 29, 1999, which is incorporated into Part III of this Form 10-K.

This report includes "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this report regarding the Company's financial position and cash requirements, estimated quantities and net present values of reserves, business strategy, plans and objectives for future operations and covenant compliance, are forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to have been correct. Important factors that could cause actual results to differ materially from the Company's expectations ("Cautionary Statements") are disclosed below under "Risk Factors" and elsewhere in this report and in other filings made by the Company with the Securities and Exchange Commission ("Commission".) The Cautionary Statements expressly qualify all subsequent written and oral forward-looking statements attributable to the Company or persons acting on its behalf.

PART I.
BUSINESS OF THE COMPANY

ITEM 1. BUSINESS

Overview

Callon Petroleum Company (the "Company") has been engaged in the acquisition, development and exploration of oil and gas properties since 1950. The Company's properties are geographically concentrated offshore in the Gulf of Mexico and onshore in Louisiana and Alabama. The Company was formed under the laws of the state of Delaware in 1994 through the consolidation of a publicly traded limited partnership, a joint venture with a consortium of European institutional investors and an independent energy company owned by certain members of current management (the "Consolidation"). As used herein, the "Company" refers to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

Over the past eight years, the Company increased its reserves through the acquisition of producing properties that were geologically complex, had (or were analogous to fields with) an established production history from stacked pay zones and were candidates for exploitation. The Company focused on reducing operating costs and implementing production enhancements through the application of technologically advanced production and recompletion techniques.

Over the past three years, the Company has also placed emphasis on the acquisition of acreage with exploration and development drilling opportunities. The Company acquired an extensive infrastructure of production platforms, gathering systems and pipelines to minimize development expenditures of these drilling opportunities. The Company also joined with Murphy Exploration and Production, Inc., ("Murphy") to explore 32 federal offshore blocks acquired in the Gulf of Mexico. The Company owns either a 20% or 25% working interest in each of the blocks. During this period, Callon has drilled 16 productive wells and nine dry holes for a total of 25 wells and a success rate of 64%. These 16 wells include two onshore, 12 in the Gulf of Mexico shelf area and two in the deepwater region of the Gulf. During 1998, six of these productive wells contributed 55 Bcfe of reserve additions. These additions from the drill bit resulted in a net reserve replacement cost of $1.15 per Mcfe.

The major focus of the Company's operations over the next two years is expected to be the exploration for and development of oil and gas properties, primarily in the Gulf of Mexico.

Business Strategy

The Company's objective is to enhance shareholder value through sustained growth in its reserve base, production levels and resulting cash flow from operations. In furtherance of this strategy, the Company (i) acquires properties with exploration and development potential; (ii) utilizes advanced technology including proprietary high resolution, shallow focus seismic technology and the latest available 3-D seismic surveys; (iii) balances lower risk, shallow target exploration in the Shallow Miocene Trend and similar geologic areas with higher risk, large target exploration; and (iv) acquires properties which provide it with the ability to control or significantly influence operations.

Exploration and Development Activities

Gulf of Mexico Shelf

Eugene Island Block 335. Three wells were drilled on Eugene Island Block 335 during 1997. The wells encountered a total of six pay sands, which, with fault separations, form eight productive reservoirs. Production facility installation was completed during the fourth quarter of 1998. During the first quarter of 1999 two dually completed wells came online at a rate of 18.4 million cubic feet of natural gas (MMcf) and 668 barrels of oil (Bo) per day. The third well is currently being completed. Callon owns a 20% working interest in the wells.

Vermilion Block 130. In March 1998 the Vermilion Block 130 #1 well reached a total measured depth of 14,134 feet (total vertical depth of 13,575 feet) and encountered approximately 85 feet of net natural gas pay in three intervals. By utilizing nearby production facilities, the discovery well went online in June 1998. It is currently producing 3 MMcf and 8 Bo per day from the deepest of the three pay zones. Callon holds a 25% working interest.

Main Pass Block 26. The State Lease 15827 #1 well at Main Pass Block 26 was drilled to a depth of 10,450 feet. The well encountered 45 feet of net natural gas pay over a gross interval from 10,084 feet to 10,218 feet. The discovery is located approximately 2.6 miles north of Callon's existing facilities at Main Pass Block 32. The well was tied-in and placed on production in February 1999. The current production rate is 5.5 MMcf and 500 Bo per day. Callon owns a 97% working interest.

Main Pass Block 36. In July 1998 Callon acquired from Conoco a 50% working interest in the Garfield prospect located on Main Pass Block 36. The SL 14964 #1 well has 40 feet of net gas pay in three zones from 13,300 feet to 16,500 feet and was tested at 14 MMcf and 900 barrels of condensate (Bc) per day. Initial production is scheduled for the second quarter of 1999.

Main Pass Block 31. The Company's State Lease 2125 #12 well, the Romeo y Julieta prospect at Main Pass Block 31, was drilled to a total depth of 12,663 feet and encountered natural gas shows over a gross interval of 107 feet. The well was perforated over an interval between 12,498 feet and 12,522 feet and tested at 2.4 MMcf and 210 Bc per day. Production should commence during the first quarter of 1999. Callon owns a 92.4% working interest in the well.

Mobile Block 864 Area. Three wells are scheduled for drilling in the Mobile Block 864 area during 1999. The wells are based upon results from a 630-mile, high-resolution, shallow-focused seismic

survey conducted during 1998. Callon's working interest in the three wells will range from 25% to 67%.

High Island 494. In February, 1998, the Company announced its High Island Block A-494 #C-1 discovery well tested at 20.3 million cubic feet of natural gas per day (MMcf/d). The #C-1 well (Snapper prospect) reached a total depth of 8,800 feet and encountered 207 feet of gross gas pay with 80 feet of net natural gas pay in the objective Cris. S. sandstone formation. It was tested on a 31/64-inch choke with a flowing tubing pressure of 2,766 pounds per square inch and shut-in tubing pressure of 3,323 pounds per square inch. Callon owns a 50% working interest in the well and the operator, Petro Quest Energy, Inc. holds the remaining 50%.

Gulf of Mexico Deepwater

Boomslang. Located in 900 feet of water, the Boomslang prospect on Ewing Bank Block 994 was drilled to a total depth of 12,955 feet and encountered 185 net feet of oil pay in three separate zones. Callon owns a 35% working interest in the block. This discovery is one of the largest discoveries in the history of the Company.

Sidewinder. Prior to development activities at Boomslang The Company plans to drill the Sidewinder prospect, located immediately to the southeast of Boomslang on Ewing Bank Block 995 and Green Canyon Blocks 24 and 25. Callon owns at 15% working interest in these leases.

Garden Banks Block 341. During February 1999 the initial test well on the Company's Habanero prospect at Garden Banks Block 341 encountered over 200 feet of net pay. Located in 2,000 feet of water, the well was drilled to a measured depth of 21,158 feet. This discovery is the second deepwater success for Callon and is expected to be the largest discovery in the Company's history. Callon owns an 11.25% working interest in the well. It is operated by Shell Deepwater Development Inc., which owns a 55% working interest, with the remaining working interest being owned by Murphy Oil.

Onshore Activity

West Lake Verret, St. Martin Parish, Louisiana. In January 1999 Callon participated in the drilling and completion of a 16,400-foot well at West Lake Verret in St. Martin Parish in south Louisiana. The Company owns a 28.7% working interest in the well, which will be placed on production in March 1999.

Kemah, Galveston County, Texas. During the first quarter of 1999 the Company drilled and completed a new field discovery well on its Kemah prospect in Galveston County, Texas. The Callon Hanson Unit #1 well tested at 3.6 MMcf and 110 Bo per day through a 20/64-inch choke with a flowing tubing pressure of 1,980 pounds per square inch. Callon owns a 100% working interest in the prospect.

Recent Acquisitions

In March 1998 Callon added to its prospect inventory by participating in Outer Continental Shelf (OCS) Lease Sale #169. The Company submitted bids on a total of 22 tracts, two for our own account and 20 in combination with seven other companies.

The shelf tracts which were awarded included five blocks with Murphy Oil Corporation, being Main Pass Block 273, Mobile Block 999, Ship Shoal Block 319, Vermilion Block 247 and West Cameron Block 276. Callon owns a 25% working interest.

The Company was also the successful high bidder on three blocks with Ranger Oil Limited: East Cameron Block 176, West Cameron Block 434 and West Cameron Block 455. Callon owns a 50% working interest and will operate. Also, Callon was the successful bidder on West Delta Block 119, which is owned 18.5% by the Company and the remainder by Murphy, Santos and Ocean Energy, Inc.

The Company also was awarded five deepwater blocks that are contiguous to Callon's Boomslang discovery at Ewing Bank Block 994. They are Ewing Bank Blocks 995 and 996 and Green Canyon Blocks 24, 25 and 27. The Company has a 15% working interest in the blocks with the balance held by Samedan Oil Corporation and Murphy.

Sale of Black Bay Complex

The Company finalized the sale of its interest in the Black Bay Complex in May 1998. Although the Company sold 9.9 Bcfe of proved reserves, the remaining upside potential of this mature oil field did not justify the high operating costs, particularly during the current low oil price environment.

Risk Factors

Volatility of Oil and Gas Prices; Marketability of Production. The Company's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. The Company's ability to maintain or increase its borrowing capacity and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. Any substantial and extended decline in the price of oil or gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. Natural gas prices were lower in 1998 than they had been in previous years. Although the decrease in gas prices was not as dramatic as the decrease in oil prices in 1998, if this condition continues for an extended period or if future gas prices fall even lower, it could adversely affect the Company in the manner described above.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, the marketability of the Company's production depends upon the availability and capacity of gas gathering systems, pipelines and processing facilities. Federal and state regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand all could adversely affect the Company's ability to produce and market its oil and natural gas. If market factors were to change dramatically,

the financial impact on the Company could be substantial. The availability of markets and the volatility of product prices are beyond the control of the Company and represent a significant risk.

Risks of Exploration and Development

The major focus of the Company's operations over the next two years is expected to be the exploration for and development of oil and gas properties, primarily in federal and state waters in the Gulf of Mexico. Exploration and drilling activities are generally considered to be of a higher risk than acquisitions of producing oil and gas properties. Additionally, certain of the Company's wells seek to discover deposits of gas at deep formations and have more risk than wells seeking to develop hydrocarbons from shallow formations. No assurances can be made that the Company will discover oil and gas in commercial quantities in its exploration and development operations. Expenditure of a material amount of funds in exploration for oil and gas without discovery of commercial quantities of reserves will have a material adverse effect upon the Company.

Operating Hazards, Offshore Operations and Uninsured Risks. Callon's operations are subject to risks inherent in the oil and gas industry, such as blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, pollution and other environmental risks. These risks could result in substantial losses to the Company due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Moreover, a substantial portion of the Company's operations are offshore and therefore are subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions, to more extensive governmental regulation, including regulations that may, in certain circumstances, impose strict liability for pollution damage, and to interruption or termination of operations by governmental authorities based on environmental or other considerations.

The Company maintains insurance of various types to cover its operations, including maritime employer's liability and comprehensive general liability. Amounts in excess of base coverages are provided by primary and excess umbrella liability policies with maximum limits of $50 million. In addition, the Company maintains operator's extra expense coverage, which provides coverage for the control of wells drilled and/or producing and redrilling expenses and pollution coverage for wells out of control.

No assurances can be given that Callon will be able to maintain adequate insurance in the future at rates the Company considers reasonable. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect the Company's financial condition and results of operations.

Estimates of Oil and Gas Reserves

This document contains estimates of oil and gas reserves, and the future net cash flows attributable to those reserves, prepared by Huddleston & Co., Inc., independent petroleum and geological engineers (the "Reserve Engineers"). There are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows attributable to such reserves, including factors beyond the control of the Company and the Reserve Engineers. Reserve engineering is a subjective process of estimating

underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and gas prices and expenditures for future development and exploitation activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploitation activities and prices of oil and gas. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and estimates set forth herein. In addition, reserve engineers may make different estimates of reserves and cash flows based on the same available data. In calculating reserves on a Mcfe basis, oil was converted to gas equivalent at the ratio of six Mcf of gas to one Bbl of oil. While this ratio approximates the energy equivalency of gas to oil on a Btu basis, it may not represent the relative prices received by the Company on the sale of its oil and gas production.

The estimated quantities of proved reserves and the discounted present value of future net cash flows attributable to estimated proved reserves set forth in this document were prepared by the Reserve Engineers in accordance with the rules of the Securities and Exchange Commission (the "Commission"), and are not intended to represent the fair market value of such reserves.

Ability to Replace Reserves

The Company's future success depends upon its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. As is generally the case in the Gulf Coast region, many of the Company's producing properties are characterized by a high initial production rate, followed by a steep decline in production. As a result, the Company must locate and develop or acquire new oil and gas reserves to replace those being depleted by production. Without successful exploration or acquisition activities, the Company's reserves and revenues will decline rapidly. No assurances can be given that the Company will be able to find and develop or acquire additional reserves at an acceptable cost.

The exploration for oil and gas requires the expenditure of substantial amounts of capital, and there can be no assurances that commercial quantities of oil or gas will be discovered as a result of such activities. The Company's current capital budget includes drilling one gross (0.5 net) development wells and 15 gross (5.7 net) exploratory wells through fiscal 1999. The estimated cost, net to the Company, to drill and complete these wells is approximately $36.9 million with dry hole costs of approximately $17.0 million. The drilling of several unsuccessful wells could have a material adverse effect on the Company. In addition, the successful acquisition of producing properties requires an assessment of recoverable reserves, future oil and gas prices and operating costs, potential environmental and other liabilities and other factors. Such assessments are necessarily inexact and their accuracy inherently uncertain. In addition, no assurances can be given that the Company's exploitation and development activities will result in any increases in reserves. The Company's operations may be curtailed, delayed or canceled as a result of lack of adequate capital and other factors, such as title problems, weather, compliance with governmental regulations or price controls, mechanical difficulties

or shortages or delays in the delivery of equipment. In addition, the costs of exploration and development may materially exceed initial estimates.

Substantial Capital Requirements

The Company makes, and will continue to make, substantial capital expenditures for the exploitation, exploration, acquisition and production of oil and gas reserves. Historically, the Company has financed these expenditures primarily with cash generated by operations, proceeds from bank borrowings and issuance of debt and equity securities. The Company's total capital expenditure budget for 1999 is approximately $55 million, and could be reduced depending on the success of the Company's drilling activities. The Company makes unsolicited offers for the acquisition of oil and gas properties in the normal course of business. In the event that any such offers are accepted, the amount or composition of the Company's capital expenditure budget could be revised significantly.

If revenues or the Company's borrowing base decrease as a result of lower oil and gas prices, operating difficulties or declines in reserves, the Company may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

Hedging of Production

Part of the Company's business strategy is to reduce its exposure to the volatility of oil and gas prices by hedging a portion of its production. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risks." In a typical hedge transaction, the Company will have the right to receive from the counterparts to the hedge, the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, the Company is required to pay the counterparts this difference multiplied by the quantity hedged. The Company is required to pay the difference between the floating price and the fixed price (when the floating price exceeds the fixed price) regardless of whether the Company has sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require the Company to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent the Company from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge. As of December 31, 1998, the Company has hedged approximately 380,000 Mcf per month from January through August of 1999 at an average floor price of $2.21 per MMBtu (NYMEX) and an average ceiling price of $2.68 per MMBtu (NYMEX). In addition, the Company had oil open collar contracts for 12,500 barrels per month from January 1999 through June 1999 at a ceiling price of $18.00 and a floor of $14.50 and 12,500 barrels per month from July 1999 through December 1999 at a ceiling price of $18.54 and a floor of $15.00.

Also at December 31, 1998 the Company had open forward sales position natural gas contracts of 200,000 Mcf per the month of March 1999 at a fixed contract average price of $2.45 and 200,000 Mcf per month from April 1999 through September 1999 at a fixed contract price of $2.35.

Competition

The Company operates in the highly competitive areas of oil and gas exploration, development and production. The availability of funds and information relating to a property, the standards established by the Company for the minimum projected return on investment, the availability of alternate fuel sources and the intermediate transportation of gas are factors which affect the Company's ability to compete in the marketplace. The Company's competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local gas gatherers, many of which possess greater financial and other resources than the Company.

Environmental and Other Regulations

The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from the Company's operations. Moreover, the recent trend toward stricter standards in environmental legislation and regulation is likely to continue. The enactment of stricter legislation or the adoption of stricter regulation could have a significant impact on the operating costs of the Company, as well as on the oil and gas industry in general.

The Company's operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Moreover, the Company could be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred; the payment of which could have a material adverse effect on the Company's financial condition and results of operations. The Company maintains insurance coverage for its operations, including limited coverage for sudden and accidental environmental damages, but does not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Moreover, the Company does not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, the Company may be subject to liability or may lose the privilege to continue exploration or production activities upon substantial portions of its properties in the event of certain environmental damages.

The Oil Pollution Act of 1990 imposes a variety of regulations on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the Oil Pollution Act of 1990, could have a material adverse impact on the Company.

Markets

Callon's ability to market oil and gas from the Company's wells depends upon numerous factors beyond the Company's control, including the extent of domestic production and imports of oil and gas, the proximity of the gas production to gas pipelines, the availability of capacity in such pipelines, the demand for oil and gas by utilities and other end users, the availability of alternative fuel sources, the effects of inclement weather, and state and federal regulation of oil and gas production and federal regulation of gas sold or transported in interstate commerce. No assurance can be given that Callon will be able to market all of the oil or gas produced by the Company or that favorable prices can be obtained for the oil and gas Callon produces.

In view of the many uncertainties affecting the supply and demand for oil, gas and refined petroleum products, the Company is unable to predict future oil and gas prices and demand or the overall effect such prices and demand will have on the Company. Callon does not believe that the loss of any of the Company's oil purchasers would have a material adverse effect on the Company's operations. Additionally, since substantially all of the Company's gas sales are on the spot market, the loss of one or more gas purchasers should not materially and adversely affect the Company's financial condition. The marketing of oil and gas by Callon can be affected by a number of factors which are beyond the Company's control, the exact effects of which cannot be accurately predicted.

Corporate Offices

The Company's headquarters are located in Natchez, Mississippi, in approximately 51,500 square feet of owned space. The Company also maintains owned or leased field offices in the area of the major fields in which it operates properties or has a significant interest. Replacement of any of the Company's leased offices would not result in material expenditures by the Company as alternative locations to its leased space are anticipated to be readily available.

Employees

The Company had 111 employees as of December 31, 1998, none of whom are currently represented by a union. The Company considers itself to have good relations with its employees. The Company employs eight petroleum engineers and four petroleum geoscientists.

Federal Regulations

Sales of Natural Gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated prices for all "first sales" of natural gas. Thus, all sales of gas by the Company may be made at market prices, subject to applicable contract provisions.

Transportation of Natural Gas. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act ("NGA"), as well as under section 311 of the Natural Gas Policy Act ("NGPA"). Since 1985, the FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

Most recently, in Order No. 636, et seq., the FERC promulgated an extensive set of new regulations requiring all interstate pipelines to "restructure" their services. The most significant provisions of

Order No. 636 (i) require that interstate pipelines provide firm and interruptible transportation solely on an "unbundled" basis, separate from their sales service, and convert each pipeline's bundled firm city-gate sales service into unbundled firm transportation service; (ii) issue blanket certificates to pipelines to provide unbundled sales service; (iii) require that pipelines provide firm and interruptible transportation service on a basis that is equal in quality for all natural gas supplies, whether purchased from the pipeline or elsewhere; (iv) require that pipelines provide a new non-discriminatory "no-notice" transportation service; (v) establish two new, generic programs for the reallocation of firm pipeline capacity; (vi) require that all pipelines offer access to their storage facilities on a firm and interruptible, open access, contract basis; (vii) provide pregranted abandonment of unbundled sales and interruptible and short-term firm transportation service and conditional pregranted abandonment of long-term transportation service; (viii) modify transportation rate design by requiring all fixed costs related to transportation to be recovered through the reservation charge under the straight fixed variable ("SFV") method. The order also recognized that the elimination of pipeline city-gate sales service and the implementation of unbundled transportation service would result in considerable costs being incurred by the pipelines. Therefore, Order No. 636 provided mechanisms for the recovery by pipelines from present, former and future customers of certain types of "transition" costs likely to occur due to these new regulations.

In subsequent orders, the FERC substantially upheld the requirements imposed by Order No. 636. Pursuant to Order No. 636, pipelines and their customers engaged in extensive negotiations in order to develop and implement new service relationships under Order No. 636. Tariffs instituting these new restructured services were placed into effect on all interstate pipelines on or before November 1, 1993. Numerous petitions for judicial review of Order No. 636 were filed and consolidated for review in the United States Court of Appeals for the D. C. Circuit. On July 16, 1996, the United States Court of Appeals for the D. C. Circuit issued its opinion and upheld the vast majority of the Order No. 636 requirements while remanding to the FERC certain limited issues. The Company can not predict what further actions the FERC may take on these matters; however, the Company does not believe that it will be affected in a manner materially different than other natural gas producers.

With respect to the transportation of natural gas on or across the Outer Continental Shelf ("OCS"), the FERC requires, as part of its regulation under the Outer Continental Shelf Lands Act, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Although to date the FERC has imposed light-handed regulation on off-shore facilities that meet its traditional test of gathering status, it has the authority to exercise jurisdiction under the Outer Continental Shelf Lands Act ("OCSLA") over gathering facilities, if necessary, to permit non-discriminatory access to service. For those facilities transporting natural gas across the OCS that are not considered to be gathering facilities, the rates, terms, and conditions applicable to this transportation are regulated by FERC under the NGA and NGPA, as well as the OCSLA.

Sales and Transportation of Crude Oil. Sales of crude oil and condensate can be made by the Company at market prices not subject at this time to price controls. The price that the Company receives from the sale of these products will be affected by the cost of transporting the products to market. The rates, terms, and conditions applicable to the interstate transportation of oil and

related products by pipelines are regulated by the FERC under the Interstate Commerce Act. As required by the Energy Policy Act of 1992, the FERC has revised its regulations governing the rates that may be charged by oil pipelines. The new rules, which were effective January 1, 1995, provide a simplified, generally applicable method of regulating such rates by use of an index for setting rate ceilings. The FERC will also, under defined circumstances, permit alternative ratemaking methodologies for interstate oil pipelines such as the use of cost of service rates, settlement rates, and market-based rates. Market-based rates will be permitted to the extent the pipeline can demonstrate that it lacks significant market power in the market in which it proposes to charge market-based rates. The cumulative effect that these rules may have on moving the Company's production to market cannot yet be determined.

With respect to the transportation of oil and condensate on or across the OCS, the FERC requires, as part of its regulation under the OCSLA, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Accordingly, the FERC has the authority to exercise jurisdiction under the OCSLA, if necessary, to permit non-discriminatory access to service.

Legislative Proposals. In the past, Congress has been very active in the area of natural gas regulation. There are legislative proposals pending in Congress and in various state legislatures which, if enacted, could significantly affect the petroleum industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on the Company's operations.

Federal, State or Indian Leases. In the event the Company conducts operations on federal, state or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management ("BLM") or Minerals Management Service or other appropriate federal or state agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. The Company owns interests in numerous federal onshore oil and gas leases. It is possible that holders of equity interests in the Company may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

State Regulations

Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rate of production

may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

The Company may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates which the Company could charge for gas, the transportation of gas, and the costs of construction and operation of such pipeline would be impacted by the rules and regulations governing such matters, if any, of such administrative authority. Further, such a pipeline system would be subject to various state and/or federal pipeline safety regulations and requirements, including those of, among others, the Department of Transportation. Such regulations can increase the cost of planning, designing, installation and operation of such facilities. The impact of such pipeline safety regulations would not be any more adverse to the Company than it would be to other similar owners or operators of such pipeline facilities.

Environmental Regulations

General. The Company's activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations regulating the release of materials in the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies thereunder, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

Activities of the Company with respect to natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing natural gas and other products, are subject to stringent environmental regulation by state and federal authorities including the United States Environmental Protection Agency ("EPA"). Such regulation can increase the cost of planning, designing, installation and operation of such facilities. In most instances, the regulatory requirements relate to water and air pollution control measures. Although the Company believes that compliance with environmental regulations will not have a material adverse effect on it, risks of substantial costs and liabilities are inherent in oil and gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production, would result in substantial costs and liabilities to the Company.

Solid and Hazardous Waste. The Company owns or leases numerous properties that have been used for production of oil and gas for many years. Although the Company has utilized operating and disposal practices standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or

released on or under these properties. In addition, many of these properties have been operated by third parties. The Company had no control over such entities' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. Under these new laws, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

The Company generates wastes, including hazardous wastes, that are subject to the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA has limited the disposal options for certain hazardous wastes and is considering the adoption of stricter disposal standards for nonhazardous wastes. Furthermore, it is possible that certain wastes currently exempt from treatment as "hazardous wastes" generated by the Company's oil and gas operations may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly disposal requirements.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed or arranged for the disposal of the hazardous substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs of such action. Neither the Company nor its predecessors has been designated as a potentially responsible party by the EPA under CERCLA with respect to any such site.

Oil Pollution Act. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill. On August 25, 1993, an advance notice of intention to adopt a rule under the OPA was published that would require owners and operators of offshore oil and gas facilities to establish $150 million in financial responsibility. Under the proposed rule, financial responsibility could be established through insurance, guaranty, indemnity, surety bond, letter of credit, qualification as a self-insurer or a combination thereof. It is unlikely

that insurance companies or underwriters will be willing to provide coverage under the OPA because the statute provides for direct lawsuits against insurers who provide financial responsibility coverage, and most insurers have strongly protested this requirement. The financial tests or other criteria that will be used to judge self-insurance are also uncertain. A number of bills are pending in the United States Congress to amend or modify the financial responsibility requirements under OPA. The Company cannot predict the final form of the financial responsibility rule that will be adopted. If the original requirements under OPA are not amended, regulations promulgated thereunder may have the potential to result in the imposition of substantial additional annual costs on the Company or otherwise materially adversely affect the Company. The impact of the rule should not be any more adverse to the Company than it will be to other similarly or less capitalized owners or operators in the Gulf of Mexico. Pending adoption of final regulations the Company has not taken any steps to establish financial responsibility under the OPA.

Air Emissions. The operations of the Company are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Administrative enforcement actions for failure to comply strictly with air regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require the Company to forego construction or operation of certain air emission sources, although the Company believes that in such case it would have enough permitted or permittable capacity to continue its operations without a material adverse effect on any particular producing field.

OSHA. The Company is subject to the requirements of the Federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and similar state statutes require the Company to organize and/or disclose information about hazardous materials used or produced in its operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

Management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on the Company.

ITEM 2. PROPERTIES

The Company is engaged in the acquisition, development, exploitation and exploration of oil and gas properties and natural gas transmission and provides oil and gas property management services for other investors. The Company's properties are concentrated offshore in the Gulf of Mexico and onshore, primarily, in Louisiana and Alabama. As of December 31, 1998, the Company's estimated proved reserves totaled 6.9 million barrels of oil and 88 billion cubic feet of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on constant prices in effect at year-end ("Discounted Cash Flow") of $99.8 million. Gas constitutes approximately 68% of the Company's total estimated proved reserves and approximately 58% of the Company's reserves are proved producing reserves. The Company operates 38 wells

representing approximately 61% of the total Discounted Cash Flow attributable to estimated proved reserves at December 31, 1998.

Significant Producing Properties

The following table shows discounted cash flows and estimated net proved oil and gas reserves by major field for the Company's five largest producing fields and for all other properties combined at December 31, 1998.

<TABLE>
<CAPTION>

Field Name/Well Location	Primary Operator(s)	Discounted Cash Flow ($000)(a)	Percent Total Discounted Cash Flow	Estimated Net Proved Oil Reserves (MBbls)	Gas Reserves (MMcf)	Total Reserves (MMcfe)
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Mobile Bay 864 Area Federal Waters	Callon/Murphy	$ 48,308	48.43%	--	41,652	41,652
Chandeleur Block 40 Federal Waters	Callon	9,505	9.53%	--	8,517	8,517
Main Pass 31 / SL 12002 #1 Louisiana State Waters	Callon	8,515	8.54%	171	4,872	5,898
Main Pass 26 / SL 15827 #1 Louisiana State Waters	Callon	6,301	6.32%	461	4,949	7,715
Main Pass 36 / SL 14964 #1 Louisiana State Waters	Callon	5,403	5.42%	163	4,414	5,392
Big Escambia Creek Southeast Alabama	Exxon	5,298	5.31%	579	1,952	5,426
Ewing Bank 994 Federal Waters	Murphy	4,241	4.25%	4,604	8,288	35,912
Eugene Island 335 Federal Waters	Murphy	3,047	3.05%	168	2,654	3,662
Other properties	Various	9,133	9.15%	752	10,732	15,244
Total		$ 99,751	100.00%	6,898	88,030	129,418

____
(a) Represents the present value of future net cash flows before deduction of federal income taxes, discounted at 10%, attributable to estimated proved reserves as of December 31, 1998, as set forth in the Company's independent reserve reports prepared by Huddleston & Co., Inc. of Houston, Texas.
</TABLE>

Mobile Block 864 Area.

The Mobile Block 864 Area is located offshore Alabama in the federal waters of the OCS. During 1997, the Company consummated four acquisitions in this area for a total of $48.7 million. In total, the Company has acquired an average 55.4% working interest in seven blocks, a 53.3% working interest in the Mobile Block 864 Area unit and the unit production facilities, a 66.7% working interest in two producing wells and a 50% working interest in another well. The Company was appointed operator of

the Mobile Block 864 unit. Estimated net proved reserves at December 31, 1998 were 41.7 Bcf and a PV-10 value of $48.3

million. Net average daily production during 1998 was 14.7 MMcf per day.

Production from three wells in the area is currently constrained by the capacity of the unit production facilities. The Company plans to add compression facilities to the existing platform to increase productive capacity during 1999.

Three wells are scheduled for drilling in the Mobile Block 864 area during 1999. The wells are based upon results from a 630-mile, high-resolution, shallow-focused seismic survey conducted during 1998. Callon's working interest in the three wells will range from 25% to 67%.

Chandeleur Block 40.

In December 1995, the Company acquired a 52.3% working (43.6% net revenue) interest in Chandeleur Block 40. When the Company assumed operations of the field, two wells were producing 5.5 MMcf/d of natural gas from the 3,800-foot sand. In February 1996, the Company shut-in one well and successfully reworked the other and increased average field production to 10.5 MMcf/d of natural gas.

During the fourth quarter of 1996, the Company drilled a development well in the field. The well resulted in a field extension which added 6 Bcf in estimated net proved reserves to the Company as of December 31, 1996. Total field production averaged approximately 15.4 MMcf/d during 1998. As of December 31, 1998 estimated net proved reserves were 8.5 Bcf with a PV-10 value of $9.5 million.

Main Pass 31 / SL 12002 #1.

Based upon a 1996 seismic survey completed by the Company, the Company negotiated two separate farm-in agreements for a 100% working interest covering a prospect with reserve potential updip from existing production in a Cib Carst reservoir on Main Pass Block 31. In August 1997, the SL 12002 #1 was drilled to a total vertical depth of 10,900 feet and encountered 67 feet of net gas pay in two zones. The Company completed the well in the lower pay zone and placed the SL 12002 #1 on production in December 1997 after flowlines were laid to a Company operated production facility at Main Pass Block 32.

The well produced 1.9 Bcf and 72,000 barrels of condensate before being recompleted into the primary pay zone in the fourth quarter of 1998. The well was brought back on-line in January at rates of 10.9 MMcf and 350 barrels of oil per day. As of December 31, 1998, estimated net proved reserves were 4.9 Bcf of gas and 171 MBbls of condensate.

Main Pass 26 / SL 15827 #1.

The Company negotiated a farm-in agreement in 1998 for a 97% working interest after identifying a prospect on the Main Pass 26 Block based upon a 1996 seismic survey completed by the Company. In August 1998 the State Lease 15827 #1 well was drilled to a depth of 10,450 feet. The well encountered 45 feet of net natural gas pay over a gross interval from 10,084 feet to 10,218 feet. The discovery is located approximately 2.6 miles north of Callon's existing facilities at Main Pass Block 32. The well was

tied-in and placed on production in February 1999. The current production rate is 5.5 MMcf and 500 Bo per day. Estimated net proved reserves at December 31, 1998 were 4.9 Bcf of natural gas and 461 MBbls of condensate with a PV-10 of $6.3 million.

Main Pass 36 / SL 14964 #1.

Callon acquired a 50% working interest in the Garfield prospect from Conoco in July 1998. The SL 14964 #1 well was completed in a reservoir located on Main Pass Block 36. The well has 40 feet of net gas pay in three zones from 13,300 feet to 16,500 feet and was tested at 14 MMcf and 900 Bc per day. Initial production is scheduled for the second quarter of 1999. Callon is the operator and estimated net proved reserves as of December 31, 1998 were 4.4 Bcf of natural gas and 163 MBbls of condensate. PV-10 of the reserves was $5.4 million.

Big Escambia Creek.

The Company owns an average working interest of 6.0% (6.6% net revenue interest), subject to a 10% reduction after payout, in nine wells and a 2.9% average royalty interest in another six wells. The gross average daily production for these wells during December 1998 was 3.0 MBbls of condensate, 1.5 MBbls of natural gas liquids, 8.0 MMcf of residue natural gas and 349 long tons of sulfur. These wells are producing from the Smackover formation at depths ranging from 15,100 to 15,600 feet. Production in this field has been partially curtailed due to low treatment plant capacity and, as a result, no significant field production decline occurred during the past several years.

Ewing Bank 994.

Located in 900 feet of water, the Boomslang prospect on Ewing Bank Block 994 was drilled to a total depth of 12,955 feet and encountered 185 net feet of oil pay in three separate zones. Callon owns a 35% working interest in the block. This discovery is one of the largest discoveries in the history of the Company. Estimated net proved reserves at December 31, 1998 were 4.6 million barrels of oil and 8.3 Bcf of natural gas. Prior to designing production facilities for Boomslang the Company plans to drill the Sidewinder prospect, located immediately to the southeast of Boomslang on Ewing Bank Block 995 and Green Canyon Blocks 24 and 25. Callon owns a 15% working interest in these leases.

Eugene Island 335.

Three wells were drilled on Eugene Island Block 335 during 1997. The wells encountered a total of six pay sands, which with fault separations, form eight productive reservoirs. Production facility installation was completed during the fourth quarter of 1998. During the first quarter of 1999 two dually completed wells came on line at a rate of 18.4 MMcf and 668 Bo per day. The third well is currently being completed. Callon owns a 20% working interest in the wells. Estimated net proved reserves at December 31, 1998 were 168 MBbls of oil and 2.7 Bcf of natural gas.

Oil and Gas Reserves

The following table sets forth certain information about the estimated proved reserves of the Company as of the dates set forth below.

	Years Ended December 31,		
	1998	1997	1996
	(In thousands)		
Proved developed:			
Oil (Bbls)	2,079	2,976	3,385
Gas (Mcf)	76,895	88,010	49,491
Proved undeveloped:			
Oil (Bbls)	4,819	426	434
Gas (Mcf)	11,135	728	933

Total proved:			
Oil (Bbls)	6,898	3,402	3,819
Gas (Mcf)	88,030	88,738	50,424
Estimated pre-tax future net cash flows	$152,552	$209,264	$216,154
Discounted cash flows	$ 99,751	$136,448	$160,171

The Company's independent Reserve Engineers prepared the estimates of the proved reserves and the future net cash flows (and present value thereof) attributable to such proved reserves. Reserves were estimated using oil and gas prices and production and development costs in effect on December 31 of each such year, without escalation, and were otherwise prepared in accordance with the Commission regulations regarding disclosure of oil and gas reserve information.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company and the reserve engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve or cash flow estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors, such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors, such as an increase or decrease in product prices that renders production of such reserves more or less economic, may justify revision of such estimates. Accordingly, reserve estimates are different from the quantities of oil and gas that are ultimately recovered.

The Company has not filed any reports with other federal agencies which contain an estimate of total proved net oil and gas reserves.

Productive Wells

The following table sets forth the wells drilled and completed by the Company during the periods indicated. All such wells were drilled in the continental United States including federal and state waters in the Gulf of Mexico.

	Years ended December 31,					
	1998		1997		1996	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	2	.40	--	--	1	.09
Gas	--	--	2	2.00	2	1.52
Non-Productive	--	--	1	0.66	--	--
Total	2	.40	3	2.66	3	1.61
Exploration:						
Oil	1	.35	--	--	--	--
Gas	3	2.14	2	.62	1	1.00
Non-Productive	2	1.25	5	1.25	--	--
Total	6	3.74	7	1.87	1	1.00

The Company owned working and royalty interests in approximately 288 gross (7.3 net) producing oil and 313 gross (23.8 net) producing gas wells as of December 31, 1998. A well is categorized as an oil well or a natural gas well based upon the ratio of oil to gas reserves on a Mcfe basis. However, substantially all of the Company's wells produce both oil and gas. At December 31, 1998, the Company had three exploratory gas wells and one exploratory oil well in progress.

Leasehold Acreage

The following table shows the approximate developed and undeveloped (gross and net) leasehold acreage of the Company as of December 31, 1998.

Leasehold Acreage

State	Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net
Alabama	13,136	12,210	944	190
California	--	--	480	480
Louisiana	11,735	8,202	6,821	3,872
Michigan	--	--	246	29
Mississippi	314	314	--	--
Oklahoma	40	10	--	--
Texas	820	378	737	626
Federal Waters	95,281	60,672	279,247	64,126
Total	121,326	81,786	288,475	69,323

As of December 31, 1998, the Company owned various royalty and overriding royalty interests in 1,336 net developed acres and 6,862 undeveloped acres. In addition, the Company owned 5,464 developed and 134,536 undeveloped mineral acres.

Major Customers

For the year ended December 31, 1998, Dynegy Marketing & Trade, PG&E Energy Trading Corp., and Columbia Energy Services purchased 23%, 26% and 22%, respectively, of the Company's natural gas and oil production. All three customers purchased production primarily from Callon owned interests' in Federal OCS leases, Chandeleur Block 40, Main Pass 163, Main Pass 164/165, Mobile Block 864 and Mobile Block 952/955 fields. Because of the nature of oil and gas operations and the marketing of production, the Company believes that the loss of these customers would not have a significant adverse impact on the Company's ability to sell its production.

Title to Properties

The Company believes that the title to its oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in the opinion of the Company, are not so material as to detract substantially from the use or value of such properties. The Company's properties are typically subject, in one degree or another, to one or more of the following: royalties and other burdens and obligations, express or implied, under oil and gas leases; overriding royalties and other burdens created by the Company or its predecessors in title; a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles; back-ins and reversionary interests existing under purchase agreements and leasehold assignments; liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; pooling, unitization and communitization agreements, declarations and orders; and easements, restrictions, rights-of-way and other matters that commonly affect property. To the extent that such burdens and obligations affect the Company's rights to production revenues, they have been taken into account in calculating the Company's net revenue interests and in estimating the size and value of the Company's reserves. The Company believes that the burdens and obligations affecting its properties are conventional in the industry for properties of the kind owned by the Company.

ITEM 3. LEGAL PROCEEDINGS

The Company is a defendant in various legal proceedings and claims, which arise in the ordinary course of Callon's business. Callon does not believe the ultimate resolution of any such actions will have a material affect on the Company's financial position or results of operations.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 1998.

PART II.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Effective April 22, 1998, the Company's Common Stock began trading on the New York Stock Exchange under the symbol "CPE". Prior to that time, the Company's Common Stock was traded on the Nasdaq National Market System under the symbol "CLNP". The following table sets forth the high and low sale prices per share as reported for the periods indicated.

Quarter Ended	High	Low
1997:		
1st Quarter	19 1/2	12 1/2
2nd Quarter	16 3/8	13 1/4
3rd Quarter	19 3/8	15
4th Quarter	22	15
1998:		
1st Quarter	17 1/8	15 1/4
2nd Quarter	18 3/8	14
3rd Quarter	14 7/8	7 7/8
4th Quarter	14	10 7/8

As of March 24, 1999, there were approximately 7,136 common stockholders of record.

The Company has not paid dividends on the Common Stock and intends to retain its cash flow from operations, net of preferred stock dividends, for the future operation and development of its business. In addition, the Company's primary credit facility restricts payments of dividends on its Common Stock.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, as of the dates and for the periods indicated, selected financial information for the Company. The financial information for each of the five years in the period ended December 31, 1998 have been derived from the audited

Consolidated Financial Statements of the Company for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of future results for the Company.

CALLON PETROLEUM COMPANY
SELECTED HISTORICAL FINANCIAL INFORMATION
(In thousands, except per share amounts)

<TABLE>
<CAPTION>

	Years Ended December 31,				
	1998	1997	1996	1995	1994
<S>	<C>	<C>	<C>	<C>	<C>
Statement of Operations Data(a):					
Revenues:					
Oil and gas sales	$ 35,624	$ 42,130	$ 25,764	$ 23,210	$ 13,948
Interest and other	2,094	1,508	946	627	171
Total revenues	37,718	43,638	26,710	23,837	14,119
Costs and expenses:					
Lease operating expenses	7,817	8,123	7,562	6,732	4,042
Depreciation, depletion and amortization	19,284	16,488	9,832	10,376	6,049
General and administrative	5,285	4,433	3,495	3,880	3,717
Interest	1,925	1,957	313	1,794	624
Accelerated vesting and retirement benefits	5,761	--	--	--	--
Impairment of oil and gas properties	43,500	--	--	--	--
Total costs and expenses	83,572	31,001	21,202	22,782	14,432
Income (loss) from operations	(45,854)	12,637	5,508	1,055	(313)
Income tax expense (benefit)	(15,100)	4,200	50	--	(200)
Net income (loss)	(30,754)	8,437	5,458	1,055	(113)
Preferred stock dividends	2,779	2,795	2,795	256	--
Net income (loss) available to common shares	$ (33,533)	$ 5,642	$ 2,663	$ 799	$ (113)
Net income (loss) per common share:					
Basic	$ (4.17)	$ .91	$ .46	$ .14	$ (.03)
Diluted	$ (4.17)	$ .88	$ .45	$ .14	$ (.03)
Shares used in computing net income (loss) per common share:					
Basic	8,034	6,194	5,835	5,755	4,346
Diluted	8,034	6,422	5,952	5,755	4,346
Balance Sheet Data (end of period)(a):					
Oil and gas properties, net	$ 141,905	$ 150,494	$ 82,489	$ 57,765	$ 43,920
Total assets	$ 181,652	$ 190,421	$ 118,520	$ 83,867	$ 73,786
Long-term debt, less current portion	$ 78,250	$ 60,250	$ 24,250	$ 100	$ 15,363
Stockholders' equity	$ 84,484	$ 113,701	$ 77,864	$ 75,129	$ 43,431

(a) The Company succeeded to the business and properties of Callon Petroleum Operating Company, Callon Consolidated Partners, L. P. ("CCP") and CN Resources ("CN") on September 16, 1994 pursuant to a consolidation. Historical information about the Company prior to September 16, 1994 includes the financial and operating information of the predecessors of the Company, other than the interest in CN not owned by Callon Petroleum Operating Company, combined as entities under common control in a manner similar to a pooling of interests.

</TABLE>

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

The following discussion is intended to assist in an understanding of the Company's financial condition and results of operations. The Company's Financial Statements and Notes thereto contain detailed information that should be referred to in conjunction with the following discussion. See Item 8. "Financial Statements and Supplementary Data."

General

Callon Petroleum Company has been engaged in the acquisition, development and exploration of oil and gas properties since 1950. The Company's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas and its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. The Company's ability to maintain or increase its borrowing capacity and to obtain additional capital on attractive terms is also influenced by oil and gas prices.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil and natural gas, the price of foreign imports and the availability of alternate fuel sources. Any substantial and extended decline in the price of crude oil or natural gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. While prices for natural gas are currently lower than they were prior to 1998, oil prices are at historic lows. The diametric change in industry conditions from the beginning of 1998 until the end of 1998 exemplifies the unpredictable nature of oil and gas prices and the external factors that can affect such prices. The Company uses derivative financial instruments (see Note 6 and Item 7A. "Quantitative and Qualitative Disclosures About Market Risks") for price protection purposes on a limited amount of its future production and does not use them for trading purposes. On a Mcfe basis, natural gas represents 84% of the projected 1999 production and 68% of proved reserves at year-end.

Inflation has not had a material impact on the Company and is not expected to have a material impact on the Company in the future.

Year 2000 Compliance

Callon, like all other enterprises that utilize computer technology, faces a threat of business disruption from the Year 2000 issue. The Year 2000 issue refers to the inability of computer and other information technology systems to properly process date and time information, stemming from the outdated programming practice of using two digits rather than four to represent the year in a date. The consequence of the Year 2000 issue is that computer and embedded processing systems are at risk of malfunctioning, particularly during the transition from 1999 to 2000.

The effects of the Year 2000 issue are exacerbated by the interdependence of computer and telecommunications systems

throughout the world. This interdependence also exists among the Company and its vendors, customers and business partners, as well as with regulators in the United States. The risks associated with the Year 2000 issue fall into three general areas: (i) financial and administrative systems, (ii) embedded systems in field process control units, and (iii) third party exposures.

Three years ago, Callon began its efforts to address the Year 2000 threat. The Company's plan is divided into three phases. Phase one involves a physical inventory of all hardware, software and devices containing date-oriented firmware. Phase two requires the Company to prioritize issues, obtain or devise solutions and make repairs or replace equipment as necessary. The third phase of the plan calls for the development of contingency plans to address, among other things, the failure of the Company's business associates to adequately address their Year 2000 problems.

As Callon has completed its inventory phase and remedial action is being taken as necessary, our attention is turned toward the Company's business partners, vendors and customers. Callon's core financial accounting software is maintained by one major vendor of oil and gas industry software. The vendor has indicated that they believe it will be Year 2000 compliant.

Overseeing our Year 2000 Project is the Callon Year 2000 Project Committee which meets on a periodic basis to review project status, provide necessary management input and resolve project issues on a timely basis. A formal review is presented to the Callon Board of Directors periodically during the year.

At this date, the Company does not anticipate that Year 2000 compliance will have a material effect on the company's financial condition or results of operations.

Total costs incurred to date and estimated remaining costs for consultants, software and hardware applications for the Year 2000 project is less than $200,000. The Company does not separately account for the internal costs incurred for its Year 2000 compliance efforts, which consist principally of payroll and related benefits for its information systems personnel.

Liquidity and Capital Resources

The Company's primary sources of capital are its cash flows from operations, borrowings and sale of debt and equity securities. Net cash and cash equivalents declined during 1998 by $9.3 million. Cash provided from operating activities during 1998 totaled $29.7 million. An additional $18 million was borrowed and $9.9 million was generated from the sale of property interests during 1998. Capital expenditures for the twelve-month period totaled $64.1 million and $2.8 million was paid as dividends on preferred stock. At December 31, 1998, the Company had working capital in the amount of $1.1 million.

Effective October 31, 1996, the Company entered into a Credit Facility with Chase Manhattan Bank. Borrowings under the Credit Facility are secured by mortgages covering substantially all of the Company's producing oil and gas properties. The Credit Facility provides for a $50 million borrowing base ("Borrowing Base") which is adjusted periodically on the basis of a discounted present value of future net cash flows attributable to the Company's proved producing oil and gas reserves. The Company may borrow, pay, reborrow and repay under the Credit Facility until October 31, 2000, on which date, the Company must repay in full all amounts then

outstanding. At December 31, 1998, the availability on this Credit

Facility was $31.9 million.

On November 27, 1996, the Company issued $24,150,000 of 10% Senior Subordinated Notes ("10% Notes") that will mature December 15, 2001. The notes are redeemable at the option of the Company, in whole or in part, at 100% of the principal amount thereof, plus accrued interest to the redemption date. The notes are general unsecured obligations of the Company, subordinated in right of payment to all existing and future indebtedness of the Company.

On July 31, 1997, the Company issued $36 million of its 10.125% Series A Senior Subordinated Notes ("Series A Notes") due 2002 in a private placement for net proceeds of $34.8 million. On September 10, 1997, pursuant to a Registration Agreement dated July 31, 1997, the Company exchanged the Series A Notes for a like principal amount of 10.125% Series B Senior Subordinated Notes due 2002 (the "Series B Notes" and, together with the Series A Notes, the "10.125% Notes"). The form and terms of the Series B Notes are identical in all material respects to the terms of the Series A Notes, except for certain transfer restrictions and provisions relating to registration rights. The 10.125% Notes are redeemable at the option of the Company in whole or in part, at any time on or after September 15, 2000. The 10.125% Notes are general unsecured obligations of the Company, subordinated in right of payment to all existing and future indebtedness of the Company and rank pari passu with the 10% Notes.

The Credit Facility and the subordinated debt contain various covenants including restrictions on additional indebtedness and payment of cash dividends as well as maintenance of certain financial ratios. The Company is in compliance with these covenants at December 31, 1998.

In November 1995, the Company sold 1,315,500 shares of $2.125 Convertible Exchangeable Preferred Stock, Series A (the "Preferred Stock"). Annual dividends are $2.125 per share and are cumulative. The net proceeds of the $.01 par value stock after underwriters discount and expense was $30,899,000. Each share has a liquidation preference of $25.00, plus accrued and unpaid dividends. Dividends on the Preferred Stock are cumulative from the date of issuance and are payable quarterly, commencing January 15, 1996. The Preferred Stock is convertible at any time, at the option of the holders thereof, unless previously redeemed, into shares of Common Stock of the Company at an initial conversion price of $11 per share of Common Stock, subject to adjustments under certain conditions.

The Preferred Stock is redeemable at any time on or after December 31, 1998, in whole or in part at the option of the Company at a redemption price of $26.488 per share beginning at December 31, 1998 and at premiums declining to the $25.00 liquidation preference by the year 2005 and thereafter, plus accrued and unpaid dividends. The Preferred Stock is also exchangeable, in whole, but not in part, at the option of the Company on or after January 15, 1998 for the Company's 8.5% Convertible Subordinated Debentures due 2010 (the "Debentures") at a rate of $25.00 principal amount of Debentures for each share of Preferred Stock. The Debentures will be convertible into Common Stock of the Company on the same terms as the Preferred Stock and will pay interest semi-annually.

On November 25, 1997, the Company completed a public offering of 1,840,000 shares at a price to the public of $17.00. This offering resulted in the Company receiving cash proceeds of $29,267,000,

net of offering costs and underwriting discount. The Company used a portion of the proceeds to repay indebtedness incurred to finance the purchase of Chevron U.S.A. Inc.'s interest in Mobile Block 864 Area (see Note 4) and the remaining proceeds were used to fund a portion of the 1998 capital expenditures budget.

In a December 1998 private transaction, a preferred stockholder elected to convert 59,689 shares of Preferred Stock into 136,867 shares of the Company's Common Stock. Subsequent to December

31, 1998, certain other preferred stockholders, through private transactions, agreed to convert 325,185 shares of Preferred Stock into 772,559 shares of the Company's Common Stock under similar terms.

Gross capital expenditures for 1998 totaled $64.1 million which included $9.5 million for the acquisition of producing properties and equipment, $47.0 million for property development and drilling activities on new and previously existing properties and $7.3 million for acquisition of oil and gas properties not yet evaluated. Cash proceeds from the sale of properties, primarily Black Bay, reduced the capital expenditures to a net of $54.2 million. The Company's plans for 1999 include capital expenditures of $55 million, primarily in the Gulf of Mexico. Projected cash flows from operations and borrowings under the Credit Facility are anticipated to be sufficient to fund this capital budget; however, the Company may consider alternative sources of financing. Future capital expenditure requirements will depend somewhat on exploration results.

Results of Operations

The following table sets forth certain operating information with respect to the oil and gas operations of the Company for each of the three years in the period ended December 31, 1998.

	December 31, 1998	1997	1996
Production:			
Oil (MBbls)	310	462	585
Gas (MMcf)	14,036	13,114	6,269
Total production (MMcfe)	15,894	15,887	9,781
Average sales price:			
Oil (per Bbl)	$ 12.41	$ 18.63	$ 18.27
Gas (per Mcf)	$ 2.26	$ 2.56	$ 2.40
Total production (per Mcfe)	$ 2.24	$ 2.65	$ 2.63
Average costs (per Mcfe):			
Lease operating expenses (excluding severance taxes)	$ .44	$ .42	$ .57
Severance taxes	$ .06	$ .09	$ .20
Depreciation, depletion and amortization	$ 1.19	$ 1.04	$ 1.01
General and administrative (net of management fees)	$ .33	$ .28	$ .36

Comparison of Results of Operations for the Years Ended December 31, 1998 and 1997

Oil and Gas Revenues

Oil and gas revenues for 1998 were $35.6 million, a 15% reduction from the 1997 amount of $42.1 million. On a Mcfe basis, 1998 production was the same as that reported for 1997. Therefore, the reduction in revenues was attributable to the 15% reduction in average sales price per Mcfe.

Oil production declined from 462,000 barrels in 1997 to 310,000 barrels in 1998 and the average sales price declined from $18.63 in 1997 to $12.41 in 1998. As a result, oil revenues declined from $8.6 million in 1997 to $3.8 million in 1998. This reduction was attributable to reduced prices and the divestiture of the Black Bay Complex in May 1998.

Gas revenues for 1998 were $31.8 million based on sales of 14 Bcf at an average sales price of $2.26 per Mcf. For 1997, gas revenues were $33.5 million based on production of 13.1 Bcf sold at an average sales price of $2.56 per Mcf.

Lease Operating Expenses and Severance Taxes

Lease operating expenses, including severance taxes, decreased from $8.1 million in 1997 to $7.8 million in 1998. Separately, severance taxes declined from $1.4 million in 1997 to $0.9 million in 1998 as a result of lower production on properties subject to severance taxes and lower oil and gas prices. Other operating expenses increased slightly from $6.7 million in 1997 to $6.9 million in 1998 as a result of a full year of costs associated with acquisitions in the fourth quarter of 1997 partially offset by a reduction due to the sale of Black Bay.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization increased as a higher rate was applied to a relatively constant production volume. Total charges increased from $16.5 million, or $1.04 per Mcfe, in 1997 to $19.3 million, or $1.19 per Mcfe in 1998. The increase in the noncash charge per Mcfe reflects the increase in investment in evaluated oil and gas properties during 1998.

General and Administrative

General and administrative expenses for 1998 were $5.3 million, or $.33 per Mcfe, compared to $4.4 million, or $.28 per Mcfe, in 1997. This 19% increase is primarily the result of the loss of Black Bay management fees, which normally reduce general and administrative expenses, and slightly higher normal corporate expenses.

Interest Expense

Interest expense for 1998 and 1997 was $1.9 million and $2.0 million, respectively.

Accelerated Vesting and Retirement Benefits

In December 1998, the Company recorded a charge of $5.8 million attributable to the accelerated vesting of the remaining performance shares previously granted under the Company's stock option plans and of retirement benefits.

Impairment of Oil and Gas Properties

Under the full-cost method of accounting, the net capitalized costs of proved oil and gas properties are subject to a "ceiling test", which limits such costs to the estimated present value, net of related tax effects (discounted at a 10 percent interest rate) of future net cash flows from proved reserves, based on current economic and operating conditions (PV10). If capitalized costs exceed this limit, the excess is charged to expense. During the fourth quarter of 1998, the Company recorded a noncash impairment provision related to oil and gas properties in the amount of $43.5 million ($28.7 million after-tax) primarily due to the significant decline in oil and gas prices.

Income Taxes

The Company's 1998 results include a deferred income tax benefit of $15.1 million primarily due to the $14.8 million deferred income tax benefit related to impairment of oil and gas properties recorded in 1998. The Company expects to realize this benefit for tax purposes in future years by utilizing its net operating loss and statutory depletion carryforwards and the turn around of temporary differences. The Company has evaluated the realizability of the deferred income tax benefit recorded above in light of its reserve quantity estimates, its long-term outlook for oil and gas prices and its expected level of other future expenses. The Company believes it is more likely than not, based upon this evaluation, that it will realize the recorded deferred income tax asset. However, there is no assurance that such asset will ultimately be realized.

Comparison of Results of Operations for the Years Ended December 31, 1997 and 1996

Oil and Gas Revenues

Total oil and gas revenues increased $16.4 million, or 63%, during 1997 to $42.1 million compared to $25.8 million in 1996. This increase in oil and gas revenues was the result of increased gas production volumes and increased average sales prices for both oil and gas.

Oil revenues for 1997 were $8.6 million based on production volume of 462,000 barrels of oil sold at an average sales price of $18.63 per barrel. For 1996, revenues were $10.7 million based on 585,000 barrels of oil sold at an average sales price of $18.27. The $2.1 million decline in oil revenues was largely attributed to normal production declines from several of the Company's oil producing properties, as well as the divestiture of certain non-core properties.

Gas revenues for 1997 were $33.5 million based on production volumes of 13.1 Bcf of gas sold at an average sales price of $2.56 per Mcf. For 1996, revenues were $15.1 million based on 6.3 Bcf of gas sold at an average sales price of $2.40. The 109% increase in production volume was largely attributed to the Company's 1996 discoveries at Chandeleur Block 40 and Main Pass 163 Area and the 1997 acquisitions in the Mobile Block 864 Area.

Lease Operating Expenses and Severance Taxes

Lease operating expenses, including severance taxes, increased from $7.6 million in 1996 to $8.1 million in 1997. Separately, severance taxes declined from $1.9 million in 1996 to $1.4 million in 1997 as a result of lower production on properties subject to severance taxes. Other operating expenses increased from $5.6 million in 1996 to $6.7 million in 1997 as a result of the new offshore producing properties. On a per Mcfe basis, these combined expenses decreased from $.77 in 1996 to $.51 in 1997.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for 1997 totaled $16.5 million, or $1.04 per Mcfe. For the same period in 1996, these expenses totaled $9.8 million, or $1.01 per Mcfe.

General and Administrative

General and administrative expenses for 1997 were $4.4 million, a 27% increase from the $3.5 million in 1996 as a result of expanded levels of operations and production. On a per Mcfe basis, these expenses decreased from $.36 in 1996 to $.28 in 1997.

Interest Expense

Interest expense for 1997 was $2.0 million. The substantial increase from the $.3 million in 1996 was reflective of the issuance of the Senior Subordinated Notes in November 1996 and July 1997.

Income Taxes

The recorded income tax expense for 1997 was $4.2 million. This amount represented the approximate statutory income tax rate, as adjusted for expected future utilization of its net operating losses and depletion carryovers. For 1996, the statutory income tax was $1.9 million, which was primarily offset by a reduction in the deferred tax asset valuation allowance.

ITEM 7A. QUANTATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

The Company's revenues are derived from the sale of its crude oil and natural gas production. From time to time, the Company has entered into hedging transactions that lock in for specified periods the prices the Company will receive for the production volumes to which the hedge relates. The hedges reduce the Company's exposure on the hedged volumes to decreases in commodities prices and limit the benefit the Company might otherwise have received from any increases in commodities prices on the hedged volumes.

At December 31, 1998, the Company had open collar contracts with third parties whereby minimum floor prices and maximum ceiling prices are contracted and applied to related contract volumes. These agreements in effect at December 31, 1998 are for average gas volumes of 380,000 Mcf per month through August of 1999 (on average) at a ceiling price of $2.68 and floor of $2.21. In addition, the Company had oil open collar contracts for 12,500 barrels per month from January 1999 through June 1999 at a ceiling price of $18.00 and a floor of $14.50 and 12,500 barrels per month from July 1999 through December 1999 at a ceiling price of $18.54 and a floor of $15.00.

Also at December 31, 1998 the Company had open forward sales position natural gas contracts of 200,000 Mcf for the month of March 1999 at a fixed contract average price of $2.45 and 200,000 Mcf per month from April 1999 through September 1999 at a fixed contract price of $2.35.

Based on projected annual sales volumes for 1999, a 10% decline in the prices the Company receives for its crude oil and natural gas production would have an approximate $2.6 million impact on the Company's revenues. The hypothetical impact on the decline in oil and gas prices is net of the incremental gain that would be realized upon a decline in prices by the oil and gas hedging contracts in place as of March 3, 1999.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders and Board of Directors of Callon Petroleum Company:

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company (a Delaware corporation) and subsidiaries as of December 31, 1998 and 1997, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Callon Petroleum Company and subsidiaries, as of December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

New Orleans, Louisiana,
February 19, 1999

CALLON PETROLEUM COMPANY
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

<TABLE>
<CAPTION>

	December 31, 1998	December 31, 1997
<S>	<C>	<C>
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,300	$ 15,597
Accounts receivable	6,024	12,168
Other current assets	1,924	723
Total current assets	14,248	28,488
Oil and gas properties, full-cost accounting method:		
Evaluated properties	444,579	398,046
Less accumulated depreciation, depletion and amortization	(345,353)	(282,891)
	99,226	115,155
Unevaluated properties excluded from amortization	42,679	35,339
Total oil and gas properties	141,905	150,494
Pipeline and other facilities, net	6,182	6,504
Other property and equipment, net	1,753	1,938
Deferred tax asset	16,348	1,248
Long-term gas balancing receivable	199	242
Other assets, net	1,017	1,507
Total assets	$ 181,652	$ 190,421

The accompanying notes are an integral part of these financial statements.

</TABLE>

CALLON PETROLEUM COMPANY
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

<TABLE>
<CAPTION>

	December 31, 1998	December 31, 1997
<S>	<C>	<C>
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 11,257	$ 12,389
Undistributed oil and gas revenues	1,720	2,259
Accrued net profits interest payable	129	1,121
Total current liabilities	13,106	15,769
Accounts payable and accrued liabilities to be refinanced	3,000	--
Long-term debt	78,250	60,250
Accrued retirement benefits	2,323	297
Long-term gas balancing payable	489	404
Total liabilities	97,168	76,720
Stockholders' equity:		
Preferred Stock, $.01 par value; 2,500,000 shares authorized; 1,255,811 shares of Convertible Exchangeable Preferred Stock, Series A issued and outstanding at December 31, 1998 and 1,315,500 outstanding at December 31, 1997 with a liquidation preference of $31,395,275 at December 31, 1998	13	13
Common Stock, $.01 par value; 20,000,000 shares authorized; 8,178,406 and 7,855,216 shares outstanding at December 31, 1998 and 1997, respectively	82	79
Treasury stock (73,800 shares at cost)	(915)	--
Unearned compensation - restricted stock	--	(2,232)
Capital in excess of par value	109,429	106,433
Retained earnings (deficit)	(24,125)	9,408
Total stockholders' equity	84,484	113,701
Total liabilities and stockholders' equity	$ 181,652	$ 190,421

The accompanying notes are an integral part of these financial statements.

</TABLE>

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 1998, 1997 and 1996
(In thousands, except per share amounts)

<TABLE>
<CAPTION>

<S>	1998	1997	1996
Revenues:			
Oil and gas sales	$ 35,624	$ 42,130	$ 25,764
Interest and other	2,094	1,508	946
Total revenues	37,718	43,638	26,710
Costs and expenses:			
Lease operating expenses	7,817	8,123	7,562
Depreciation, depletion and amortization	19,284	16,488	9,832
General and administrative	5,285	4,433	3,495
Interest	1,925	1,957	313
Accelerated vesting and retirement benefits	5,761	--	--
Impairment of oil and gas properties	43,500	--	--
Total costs and expenses	83,572	31,001	21,202
Income (loss) from operations	(45,854)	12,637	5,508
Income tax expense (benefit)	(15,100)	4,200	50
Net income (loss)	(30,754)	8,437	5,458
Preferred stock dividends	2,779	2,795	2,795
Net income (loss) available to common shares	$ (33,533)	$ 5,642	$ 2,663
Net income (loss) per common share:			
Basic	$ (4.17)	$ .91	$ .46
Diluted	$ (4.17)	$ .88	$ .45
Shares used in computing net income (loss) per common share:			
Basic	8,034	6,194	5,835
Diluted	8,034	6,422	5,952

The accompanying notes are an integral part of these financial statements.

</TABLE>

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

<TABLE>
<CAPTION>

Unearned Compensation	Capital in	Retained

	Preferred Stock	Common Stock	Treasury Stock	Restricted Stock	Excess of Par Value	Earnings (Deficit)
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Balances, December 31, 1995	$ 13	$ 58	$ --	$ --	$ 73,955	$ 1,103
Net income	--	--	--	--	--	5,458
Preferred stock dividends	--	--	--	--	--	(2,795)
Shares issued pursuant to employee benefit plan	--	--	--	--	72	--
Balances, December 31, 1996	13	58	--	--	74,027	3,766
Net income	--	--	--	--	--	8,437
Sale of common stock	--	19	--	--	29,249	--
Preferred stock dividends	--	--	--	--	--	(2,795)
Tax benefits related to stock compensation plans	--	--	--	--	36	--
Shares issued pursuant to employee benefit and option plan	--	--	--	--	392	--
Restricted stock plan	--	2	--	(3,153)	2,729	--
Earned portion of restricted stock	--	--	--	921	--	--
Balances, December 31, 1997	13	79	--	(2,232)	106,433	9,408
Net income (loss)	--	--	--	--	--	(30,754)
Preferred stock dividends	--	--	--	--	15	(2,779)
Shares issued pursuant to employee benefit and option plan	--	--	--	--	235	--
Employee stock purchase plan	--	--	--	--	163	--
Restricted stock plan	--	2	--	(2,731)	2,584	--
Earned portion of restricted stock	--	--	--	4,963	--	--
Conversion of preferred shares to common	--	1	--	--	(1)	--
Stock buyback plan	--	--	(915)	--	--	--
Balances, December 31, 1998	$ 13	$ 82	$ (915)	$ --	$ 109,429	$ (24,125)

The accompanying notes are an integral part of these financial statements.

</TABLE>

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 1998, 1997 and 1996
(In thousands)

<TABLE>
<CAPTION>

	1998	1997	1996
<S>	<C>	<C>	<C>
Cash flows from operating activities:			
Net income (loss)	$ (30,754)	$ 8,437	$ 5,458
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	19,791	16,924	10,131
Impairment of oil and gas properties	43,500	--	--
Amortization of deferred costs	619	467	114

Deferred income tax expense (benefit)	(15,100)	4,200	50
Noncash compensation related to stock compensation plans	7,583	1,224	72
Changes in current assets and liabilities:			
Accounts receivable	6,144	493	(4,332)
Other current assets	(1,201)	(207)	(278)
Current liabilities	(860)	(3,809)	4,049
Change in gas balancing receivable	43	418	(41)
Change in gas balancing payable	85	14	(42)
Change in other long-term liabilities	--	249	(28)
Change in other assets, net	(129)	(1,073)	(830)
Cash provided (used) by operating activities	29,721	27,337	14,323
Cash flows from investing activities:			
Capital expenditures	(64,105)	(89,609)	(37,637)
Cash proceeds from sale of mineral interests	9,909	4,450	1,574
Cash provided (used) by investing activities	(54,196)	(85,159)	(36,063)
Cash flows from financing activities:			
Change in accrued liabilities for capital expenditures	(2,396)	3,610	3,346
Increase in accounts payable and accrued liabilities to be refinanced	3,000	--	--
Equity issued related to employee stock plans	414	90	--
Purchase of treasury shares	(915)	--	--
Payments on debt	--	(49,200)	(25,850)
Proceeds from debt issuance	18,000	85,200	50,000
Common stock canceled	(130)	(422)	--
Sale of common stock	--	29,267	--
Increase (decrease) in accrued preferred stock dividends payable	(16)	--	443
Dividends on preferred stock	(2,779)	(2,795)	(2,795)
Cash provided (used) by financing activities	15,178	65,750	25,144
Net increase (decrease) in cash and cash equivalents	(9,297)	7,928	3,404
Cash and cash equivalents:			
Balance, beginning of period	15,597	7,669	4,265
Balance, end of period	$ 6,300	$ 15,597	$ 7,669

The accompanying notes are an integral part of these financial statements.

</TABLE>

CALLON PETROLEUM COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

Callon Petroleum Company (the "Company") was organized under the laws of the state of Delaware in March 1994 to serve as the surviving entity in the consolidation and combination of several related entities (referred to herein collectively as the "Constituent Entities"). The combination of the businesses and properties of the Constituent Entities with the Company was completed on September 16, 1994 (the "Consolidation").

As a result of the Consolidation, all of the businesses and properties of the Constituent Entities are owned (directly or indirectly) by the Company. Certain registration rights were granted to the stockholders of certain of the Constituent Entities. See Note 7.

The Company and its predecessors have been engaged in the acquisition, development and exploration of crude oil and natural gas since 1950. The Company's properties are geographically concentrated in Louisiana, Alabama, Texas and offshore Gulf of Mexico.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Reporting

The Consolidated Financial Statements include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company ("CPOC"). CPOC also has subsidiaries, namely Callon Offshore Production, Inc. and Mississippi Marketing, Inc. All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to presentation in the current year.

Use of Estimates

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

Accounting Pronouncements

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133 ("FAS 133"), Accounting for Derivative Instruments and Hedging Activities. The Statement establishes accounting and reporting standards requiring that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded in the balance sheet as either an asset or liability measured at its fair value. FAS 133 is effective for fiscal years beginning after June 15, 1999, with earlier application permitted. The Company has not yet determined the timing or method of the adoption of FAS 133 and thus cannot quantify the impact of adoption. However, the Statement will create volatility in equity through other comprehensive income.

In June 1997, the Financial Accounting Standards Board issued Statement No. 130 ("FAS 130"), Reporting Comprehensive Income. FAS 130 establishes standards for reporting and display of comprehensive income and its components in a full set of general purpose financial statements. FAS 130 was effective for the Company in 1998. The Company does not have any items of other comprehensive income.

Also in 1997, the Financial Accounting Standards Board issued Statement No. 131 ("FAS 131"), Disclosures about Segments of an Enterprise and Related Information. FAS 131 establishes standards for the way that public business enterprises report information about operating segments in annual financial statements and requires that those enterprises report selected information about operating segments in interim financial reports issued to shareholders. The Company has only one operating segment and thus separate segment disclosure is not required.

Property and Equipment

The Company follows the full-cost method of accounting for oil and gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and gas reserves, including certain overhead costs, are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, interest capitalized on unevaluated leases and other costs related to exploration and development activities. Payroll and general and administrative costs capitalized include salaries and related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and gas properties as well as other directly identifiable general and administrative costs associated with such activities. Costs associated with unevaluated properties are excluded from amortization. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties, the properties are sold or management determines these costs have been impaired.

Costs of properties, including future development and net future site restoration, dismantlement and abandonment costs, which have proved reserves and those which have been determined to be worthless, are depleted using the unit-of-production method based on proved reserves.

If the total capitalized costs of oil and gas properties, net of amortization, exceed the sum of (1) the estimated future net revenues from proved reserves at current prices and discounted at 10% and (2) the lower of cost or market of unevaluated properties (the full-cost ceiling amount), net of tax effects, then such excess is charged to expense during the period in which the excess occurs. See Note 8.

Upon the acquisition or discovery of oil and gas properties, management estimates the future net costs to be incurred to dismantle, abandon and restore the property using geological, engineering and regulatory data available. Such cost estimates are periodically updated for changes in conditions and requirements. Such estimated amounts are considered as part of the full cost pool subject to amortization upon acquisition or discovery. Such costs are capitalized as oil and gas properties as the actual restoration, dismantlement and abandonment activities take place. As of December 31, 1998 and 1997, estimated future site restoration, dismantlement and abandonment costs, net of related salvage value and amounts funded by abandonment trusts (see Notes 7 and 9) were not material.

Depreciation of other property and equipment is provided using the straight-line method over estimated lives of three to twenty years. Depreciation of the pipeline and other facilities is provided using the straight-line method over estimated lives of 15 to 27 years.

Natural Gas Imbalances

The Company follows an entitlement method of accounting for its proportionate share of gas production on a well by well basis, recording a receivable to the extent that a well is in an "undertake" position and conversely recording a liability to the extent that a well is in an "overtake" position.

Derivatives

The Company uses derivative financial instruments (see Note 6) for price protection purposes on a limited amount of its future production and does not use them for trading purposes. Such derivatives are accounted for on an accrual basis and amounts paid or received under the agreements are recognized as oil and gas sales in the period in which they accrue.

Accounts Receivable

Accounts receivable consists primarily of accrued oil and gas production receivable. The balance in the reserve for doubtful accounts included in accounts receivable is $38,000 and $36,000 at December 31, 1998 and 1997, respectively. Net recoveries were $2,000 in 1998 and net charge offs were $357,000 and $88,000 in 1997 and 1996. There were no provisions to expense in the three year period ended December 31, 1998.

For the year ended December 31, 1998, three companies purchased 23%, 26% and 22%, respectively of the Company's natural gas and oil production. All three customers purchased production primarily from Callon owned interests' in Federal OCS leases, CB40, MP163, MP 164/165, MB 864 and MB 952/955 fields. Because of the nature of oil and gas operations and the marketing of production, the Company believes that the loss of these customers would not have a significant adverse impact on the Company's ability to sell its productions.

Statements of Cash Flows

For purposes of the Consolidated Financial Statements, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

The Company paid no federal income taxes for the three years ended December 31, 1998. During the years ended December 31, 1998, 1997 and 1996, the Company made cash payments of $6,229,000, $4,167,000, and $251,000, respectively, for interest.

Per Share Amounts

In February 1997, the Financial Accounting Standards Board issued

Statement No. 128 ("FAS 128"), Earnings per Share, which generally simplified the manner in which earnings per share are determined. The Company adopted FAS 128 effective December 15, 1997. In accordance with FAS 128, the Company's previously reported earnings per share for 1996 were restated. The effect of this accounting change on previously reported earnings per share (EPS) data was as follows:

Per share amounts	1996
Primary EPS as reported	$ .45
Effect of FAS 128	.01
Basic EPS as restated	$ .46
Fully diluted EPS as reported	$ .43
Effect of FAS 128	.02
Diluted EPS as restated	$ .45

Basic earnings or loss per common share were computed by dividing net income or loss by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share for the

years 1997 and 1996 were determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options considered common stock equivalents computed using the treasury stock method. In 1998, all options were excluded from the computation of diluted loss per share because they were antidilutive. The conversion of the preferred stock was not included in any annual calculation due to their antidilutive effect on diluted income or loss per share.

A reconciliation of the basic and diluted per share computation is as follows (in thousands, except per share amounts):

	1998	1997	1996
(a) Net income (loss) available for common stock	$ (33,533)	$ 5,642	$ 2,663
(b)Weighted average shares outstanding	8,034	6,194	5,835
(c)Dilutive impact of stock options	--	228	117
(d)Total diluted shares	8,034	6,422	5,952
Stock options excluded due to antidilutive impact	163	--	--
Basic earnings (loss) per share (a/b)	$ (4.17)	$ .91	$ .46
Diluted earnings (loss) per share (a/d)	$ (4.17)	$ .88	$ .45

Fair Value of Financial Instruments

Fair value of cash, cash equivalents, accounts receivable, accounts payable and long-term debt approximates book value at December 31, 1998 and 1997. Fair value of long-term debt (specifically the 10% and the 10.125% senior subordinated notes) was based on quoted market value.

The calculation of the fair market value of the outstanding hedging contracts (see Note 6) as of December 31, 1998 indicated a $1.4 million market value benefit to the Company based on market prices at that date.

Accounts Payable and Accrued Liabilities - Long-Term

Approximately $3,000,000 of current accounts payable and accrued liabilities at December 31, 1998 related to long-term assets, primarily oil and gas properties that were financed subsequent to year-end with long-term debt and therefore have been reclassified as long-term.

3. INCOME TAXES

The Company follows the asset and liability method of accounting for deferred income taxes prescribed by Financial Accounting Standards Board Statement No. 109 ("FAS 109") "Accounting for Income Taxes". The statement provides for the recognition of a deferred tax asset for deductible temporary timing differences, capital and operating loss carryforwards, statutory depletion carryforward and tax credit carryforwards, net of a "valuation allowance". The valuation allowance is provided for that portion of the asset, for which it is deemed more likely than not, that it will not be realized. The Company's management determined that no valuation allowance was necessary in 1998 and 1997. Accordingly, the Company has recorded a deferred tax asset at December 31, 1998 and 1997 as follows:

	December 31, 1998	December 31, 1997
	(In thousands)	
Federal net operating loss carryforward	$ 7,916	$ 3,531
Statutory depletion carryforward	4,083	4,062
Temporary differences:		
Oil and gas properties	3,979	(4,943)
Pipeline and other facilities	(2,164)	(2,277)
Non-oil and gas property	(101)	(86)
Other	2,635	961
Total tax asset	16,348	1,248
Valuation allowance	--	--
Net tax asset	$ 16,348	$ 1,248

At December 31, 1998, the Company had, for federal tax reporting purposes, net operating loss carryforwards ("NOL") of $22.6 million which expire in 2000 through 2012. Approximately $5.0 million of such carryovers are subject to limitations on utilization as a result of ownership changes which occurred in CPOC's common stock prior to the Consolidation and ownership changes as a result of the Consolidation. Additionally, the Company had available for tax reporting purposes $11.7 million in statutory depletion deductions which can be carried forward for an indefinite period.

The provision for income taxes at the Company's effective tax rate differed from the provision for income taxes at the statutory rate as follows:

	December 31, 1998	1997	1996
	(In thousands)		
Computed expense (benefit) at the expected statutory rate	$ (15,590)	$ 4,296	$ 1,910
Change in valuation allowance	--	--	(1,760)
Other	490	(96)	(100)
Deferred income tax expense (benefit)	$ (15,100)	$ 4,200	$ 50

4. ACQUISITIONS

On June 26, 1997 the Company purchased an 18.8% working interest in the Mobile Block 864 Area from Elf Exploration, Inc. The Company's net purchase price was approximately $11.8 million. The Company further increased its ownership in this area by purchasing Chevron U.S.A. Inc.'s interest in the Mobile Block 864 Area for $18.8 million in November 1997.

The Company, together with an industry partner, was the high bidder on 18 offshore tracts at the Outer Continental Shelf ("OCS") Lease Sale #157 and #161, held during 1996 in New Orleans, Louisiana, and conducted by the U. S.

Department of the Interior through its Minerals Management Service ("MMS"). The Company holds a 25% working interest in the leases and its share of the total lease costs was approximately $15.2 million.

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

	December 31, 1998	December 31, 1997
	(In thousands)	
Credit Facility	$ 18,100	$ 100
10% Senior Subordinated Notes	24,150	24,150
10.125% Senior Subordinated Notes	36,000	36,000
	78,250	60,250
Less: current portion	--	--
	$ 78,250	$ 60,250

Borrowings under the Credit Facility, with Chase Manhattan Bank, are secured by mortgages covering substantially all of the Company's producing oil and gas properties. Currently, the Credit Facility provides for a $50 million borrowing base ("Borrowing Base") which is adjusted periodically on the basis of a discounted present value of future net cash flows attributable to the Company's proved producing oil and gas reserves. Pursuant to the Credit Facility, depending upon the percentage of the unused portion of the borrowing base, the interest rate is equal to the lender's prime rate plus 0.125% (prime plus 0.50% if utilized percentage of borrowing base is greater than 50%). The Company, at its option, may fix the interest rate on all or a portion of the outstanding principal balance at 1.125% above a defined "Eurodollar" rate for periods up to six months (1.5% above if utilized percentage of borrowing base is greater than 50%). The weighted average interest rate for the total debt outstanding at December 31, 1998 and 1997 was 6.68% and 8.50%, respectively. Under the Credit Facility, a commitment fee of .25% or .375% per annum on the unused portion of the Borrowing Base (depending upon the percentage of the unused portion of the Borrowing Base) is payable quarterly. The Company may borrow, pay, reborrow and repay under the Credit Facility until October 31, 2000, on which date, the Company must repay in full all amounts then outstanding.

On November 27, 1996, the Company issued $24,150,000 of 10% Senior Subordinated Notes that will mature December 15, 2001. The Company used the proceeds to reduce borrowings under the Credit Facility and for other corporate purposes. Interest is payable quarterly beginning March 15, 1997. The notes are redeemable at the option of the Company, in whole or in part, on or after December 15, 1997, at 100% of the principal amount thereof, plus accrued interest to the redemption date. The notes are general unsecured obligations of the Company, subordinated in right of payment to all existing and future indebtedness of the Company.

On July 31, 1997, the Company issued $36 million of its 10.125% Series A Senior Subordinated Notes due 2002. Interest is payable quarterly beginning September 15, 1997. The Senior Subordinated Notes were offered through a private placement transaction. The net proceeds of the transaction were used to repay the outstanding balance under the Credit Facility and fund a portion of the Company's capital expenditure budget. On September 10, 1997, the Company commenced an offer to exchange the Series A Notes for a like principal amount of 10.125% Series B Senior Subordinated Notes due 2002 (the "Series B Notes" and, together with the Series A Notes, the "10.125% Notes"). The form and terms of the Series B Notes are identical in all material respects to the terms of the Series A Notes, except for certain transfer restrictions and provisions relating to registration rights. The exchange offer was completed on November 10, 1997. Interest on the 10.125% Notes is payable quarterly, on March 15, June 15, September 15, and December 15 of each year. The 10.125% Notes are redeemable at the option of the Company in whole or in part, at any time on or after September 15, 2000. The 10.125% Notes are general unsecured obligations of the Company, subordinated in right of payment to all existing and future indebtedness of the Company and rank pari passu with the 10% Notes.

The Credit Facility and the subordinated debt contain various covenants including restrictions on additional indebtedness and payment of cash dividends as well as maintenance of certain financial ratios. The Company is in compliance with these covenants at December 31, 1998.

6. HEDGING CONTRACTS

The Company periodically uses derivative financial instruments to manage oil and gas price risk. Settlements of gains and losses on commodity price swap contracts are generally based upon the difference between the contract price or prices specified in the derivative instrument and a NYMEX price or other cash or futures index price, and are reported as a component of oil and gas revenues. Gains or losses attributable to the termination of a swap contract are deferred and recognized in revenue when the oil and gas production is sold. Approximately $1,886,000 and $2,466,000 was recognized as additional oil and gas revenue in 1998 and 1997 and recognized a reduction in revenue of $2,757,000 in 1996 as a result of such agreements. At December 31, 1998, the Company had open collar contracts with third parties whereby minimum floor prices and maximum ceiling prices are contracted and applied to related contract volumes. These agreements in effect at December 31, 1998 are for average gas volumes of 380,000 Mcf per month through August of 1999 (on average) at a ceiling price of $2.68 and floor of $2.21. In addition, the Company had oil open collar contracts for 12,500 barrels per month from January 1999 through June 1999 at a ceiling price of $18.00 and a floor of $14.50 and 12,500 barrels per month from July 1999 through December 1999 at a ceiling price of $18.54 and a floor of $15.00.

Also at December 31, 1998 the Company had open forward sales position natural gas contracts of 200,000 Mcf for the month of March 1999 at a fixed contract average price of $2.45 and 200,000 Mcf per month from April 1999 through September 1999 at a fixed contract price of $2.35.

7. COMMITMENTS AND CONTINGENCIES

As described in Note 9, abandonment trusts (the "Trusts") have been established for future abandonment obligations of those oil and gas properties of the Company burdened by a net profits interest. The management of the Company believes the Trusts will be sufficient to offset those future abandonment liabilities; however, the Company is responsible for any abandonment expenses in excess of the Trusts' balances. As of December 31, 1998, total estimated site restoration, dismantlement and abandonment costs were approximately $6,360,000, net of expected salvage value. Substantially all such costs are expected to be funded through the Trusts' funds, all of which will be accessible to the Company when abandonment work begins. In addition as a working interest owner and/or operator of oil and gas properties, the Company is responsible for the cost of abandonment of such properties. See Note 2.

The Company, as part of the Consolidation, entered into Registration Rights Agreements whereby the former stockholders of certain of the Constituent Entities are entitled to require the Company to register Common Stock of the Company owned by them with the Securities and Exchange Commission for sale to the public in a firm commitment public offering and generally to include shares owned by them, at no cost, in registration statements filed by the Company. Costs of the offering will not include discounts and commissions, which will be paid by the respective sellers of the Common Stock.

8. OIL AND GAS PROPERTIES

The following table discloses certain financial data relating to the Company's oil and gas activities, all of which are located in the United States.

	Years Ended December 31, 1998	1997	1996
	(In thousands)		
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$ 398,046	$ 322,970	$ 304,737
Property acquisition costs	9,464	51,751	2,999
Exploration costs	42,617	13,620	8,732
Development costs	4,361	14,155	8,076
Sale of mineral interests	(9,909)	(4,450)	(1,574)
End of period balance	$ 444,579	$ 398,046	$ 322,970
Unevaluated Properties (excluded from the full-cost pool) -			
Beginning of period balance	$ 35,339	$ 26,235	$ 10,171
Additions	11,156	16,924	20,640
Capitalized interest and general and administrative costs	8,955	5,163	1,883
Transfers to evaluated	(12,771)	(12,983)	(6,459)
End of period balance	$ 42,679	$ 35,339	$ 26,235
Accumulated depreciation, depletion and amortization-			
Beginning of period balance	$ 282,891	$ 266,716	$ 257,143
Provision charged to expense	18,962	16,175	9,573
Impairment of oil and gas properties	43,500	--	--
End of period balance	$ 345,353	$ 282,891	$ 266,716

Unevaluated property costs, primarily lease acquisition costs incurred at federal and state lease sales and unevaluated drilling costs being excluded from the amortizable evaluated property base consisted of $17.9 million incurred in 1998, $8.2 million incurred in 1997 and $16.6 million incurred in 1996 and prior. These costs are directly related to the acquisition and evaluation of unproved properties and major development projects. The excluded costs and related reserves are included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. The majority of these costs will be evaluated over the next five year period.

Depreciation, depletion and amortization per unit-of-production (equivalent barrel of oil) amounted to $7.16, $6.11, and $5.87 for the years ended December 31, 1998, 1997 and 1996, respectively.

Impairment of Oil and Gas Properties

Under full-cost accounting rules, the capitalized costs of proved oil and gas properties are subject to a "ceiling test", which limits such costs to the estimated present value net of related tax effects, discounted at a 10 percent interest rate, of future net cash flows from proved reserves, based on current economic and operating conditions (PV10). If capitalized costs exceed this limit, the excess is charged to expense. During the fourth quarter of 1998, the Company recorded a noncash impairment provision related to oil and gas properties in the amount of $43.5 million ($28.7 million after-tax) primarily due to the significant decline in oil and gas prices.

9. NET PROFITS INTEREST

Since 1989, the Constituent Entities have entered into separate agreements to purchase certain oil and gas properties with gross contract acquisition prices of $170,000,000 ($150,000,000 net as of closing dates) and in simultaneous transactions, entered into agreements to sell overriding royalty interests ("ORRI") in the acquired properties. These ORRI are in the form of net profits interests ("NPI") equal to a significant percentage of the excess of gross proceeds over production costs, as defined, from the acquired oil and gas properties. A net deficit incurred in any month can be carried forward to subsequent months until such deficit is fully recovered. The Company has the right to abandon the purchased oil and gas properties if it deems the properties to be uneconomical.

The Company has, pursuant to the purchase agreements, created abandonment trusts whereby funds are provided out of gross production proceeds from the properties for the estimated amount of future abandonment obligations related to the working interests owned by the Company. The Trusts are administered by unrelated third party trustees for the benefit of the Company's working interest in each property. The Trust agreements limit their funds to be disbursed for the satisfaction of abandonment obligations. Any funds remaining in the Trusts after all restoration, dismantlement and abandonment obligations have been met will be distributed to the owners of the properties in the same ratio as contributions to the Trusts. The Trusts' assets are excluded from the Consolidated Balance Sheets of the Company because the Company does not control the Trusts. Estimated future revenues and costs associated with the NPI and the Trusts are also excluded from the oil and gas reserve disclosures at Note 12. As of December 31, 1998 and 1997 the Trusts' assets (all cash and investments) totaled $6,360,000 and $19,300,000, respectively, all of which will be available to the Company to pay its portion, as working interest owner, of the restoration, dismantlement and abandonment costs discussed at Note 7. The trust asset decrease in 1998 was the result of a sale of an oil and gas property and the related trust.

At the time of acquisition of properties by the Company, the property owners estimated the future costs to be incurred for site restoration, dismantlement and abandonment, net of salvage value. A portion of the amounts necessary to pay such estimated costs was deposited in the Trusts upon acquisition of the properties, and the remainder is deposited from time to time out of the proceeds from production. The determination of the amount deposited upon the acquisition of the properties and the amount to be deposited as proceeds from production was based on numerous factors, including the estimated reserves of the properties. The amounts deposited in the Trusts upon acquisition of the properties were capitalized by the Company as oil and gas properties.

As operator, the Company receives all of the revenues and incurs all of the production costs for the purchased oil and gas properties but retains only that portion applicable to its net ownership share. As a

result, the payables and receivables associated with operating the properties included in the Company's Consolidated Balance Sheets include both the Company's and all other outside owner's shares. However, revenues and production costs associated with the acquired properties reflected in the accompanying Consolidated Statements of Operations represent only the Company's share, after reduction for the NPI.

10. EMPLOYEE BENEFIT PLANS

The Company has adopted a series of incentive compensation plans designed to align the interest of the executives and employees with those of its stockholders. The following is a brief description of each plan:

- The Savings and Protection Plan provides employees with the option to defer receipt of a portion of their compensation and the Company may, at its discretion, match a portion of the employee's deferral with cash and Company Common Stock. The Company may also elect, at its discretion, to contribute a non-matching amount in cash and Company Common Stock to employees. The amounts held under the Savings and Protection Plan are invested in various funds maintained by a third party in accordance with the directions of each employee. An employee is fully vested immediately upon participation in the Savings and Protection Plan. The total amounts contributed by the

Company, including the value of the common stock contributed, were $468,000, $438,000, and $241,000 in the years 1998, 1997 and 1996, respectively.

- The 1994 Stock Incentive Plan (the "1994 Plan") provides for 600,000 shares of Common Stock to be reserved for issuance pursuant to such plan. Under the 1994 Plan the Company may grant both stock options qualifying under Section 422 of the Internal Revenue Code and options that are not qualified as incentive stock options, as well as performance shares. No options will be granted at an exercise price of less than fair market value of the Common Stock on the date of grant. A total of 500,000 options were granted in 1994 and 1995 and all such options could be exercised as of December 31, 1996. During 1997, there were no other options granted and 9,000 shares were exercised at an average price of $17.94. These options have an expiration date 10 years from date of grant. In 1998, 20,000 non-employee director options were granted under the plan, vesting 100% in November 1998.

- On August 23, 1996, the Board of Directors of the Company approved and adopted the Callon Petroleum Company 1996 Stock Incentive Plan (the "1996 Plan"). The 1996 Plan provides for the same types of awards as the 1994 Plan and is limited to a maximum of 1,200,000 shares (as amended from the original 900,000 shares) of common stock that may be subject to outstanding awards. During 1998, 1997 and 1996, the Company granted stock options to purchase 205,000, 20,000 and 530,000 shares, respectively, of Common Stock under the plan. All of such options were granted at an exercise price equal to the fair market value of the Common Stock on the date of grant. Terms of the options granted in 1998 provide that 25% of the options become exercisable each year beginning August of 1998 and each succeeding January. Terms of the plan for 450,000 options granted in 1996 provide that 20% of the options become exercisable on January 1 of each succeeding year, beginning January 1, 1997. Non-employee director options aggregating 80,000 shares vest 25% at each succeeding annual meeting of directors following each annual stockholders' meeting, beginning in 1997. Unvested options are subject to forfeiture upon certain termination of employment events and expire 10 years from date of grant.

The Company accounts for the options issued pursuant to the stock incentive plans under APB Opinion No. 25, under which no compensation cost has been recognized. Had compensation cost for these plans been determined consistent with FAS 123, the Company's net income and earnings per common share would have been reduced to the following pro forma amounts:

		1998	1997	1996
		(In thousands, except per share data)		
Net income (loss):	As Reported	$ (33,533)	$ 5,642	$ 2,663
	Pro Forma	(34,421)	4,977	2,411
Basic earnings (loss) per share:	As Reported	(4.17)	.91	.46
	Pro Forma	(4.28)	.80	.41
Diluted earnings (loss) per share:	As Reported	(4.17)	.88	.45
	Pro Forma	(4.28)	.77	.41

Because the Statement 123 method of accounting has not been applied to options granted prior to January 1, 1995, the resulting pro forma compensation cost above may not be representative of that to be expected in future years.

A summary of the status of the Company's two stock option plans at December 31, 1998, 1997 and 1996 and changes during the years then ended is presented in the table and narrative below:

<TABLE>
<CAPTION>
1998 1997 1996

<S>	<C> Shares	<C> Wtd Avg Ex Price	<C> Shares	<C> Wtd Avg Ex Price	<C> Shares	<C> Wtd Avg Ex Price
Outstanding, beginning of year	1,041,000	$ 11.19	1,030,000	$ 11.10	490,000	$ 10.01
Granted	225,000	10.08	20,000	15.31	550,000	12.06
Exercised	--	--	(9,000)	10.00	--	--
Forfeited	--	--	--	--	(10,000)	10.00
Expired	--	--	--	--	--	--
Outstanding, end of year	1,266,000	$ 11.00	1,041,000	$ 11.19	1,030,000	$ 11.10
Exercisable, end of year	802,250	$ 10.90	621,000	$ 10.65	500,000	$ 10.16
Weighted average fair value of options granted	$ 4.31		$ 6.30		$ 4.96	

</TABLE>

The options outstanding at December 31, 1998 have exercise prices ranging from $9.47 to $16.38 with a remaining weighted average contractual life of 7.06 years.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for options granted during 1998, 1997 and 1996.

	1998	1997	1996
Risk free interest rate	5.1%	6.8 %	6.5 %
Expected life (years)	7.0	4.0	4.9
Expected volatility	28.8%	41.1 %	34.7 %
Expected dividends	--	--	--

The Company awarded 225,000 performance shares under the 1996 Plan to the Company's Executive officers on August 23, 1996. During June 1997, the Company's stockholders approved the performance share awards and the related common stock was issued. The issuance was recorded at the fair market value of the shares on their date of grant, with a corresponding charge to stockholders' equity representing the unearned portion of the award. All of the performance shares granted will vest in whole on January 1, 2001, and will be subject to forfeiture upon certain termination of employment events. The unearned portion was being amortized as compensation expense on a straight-line basis over the vesting period. An additional 25,000 shares were issued under the 1994 Plan in 1997 and 165,500 shares were issued to certain key employees other than the Company's Executive officers in 1998. Approximately $4,963,000 in 1998, $714,000 in 1997 and $208,000 in 1996 of compensation cost were charged to expense related to the restricted shares granted.

In December 1998, the Company approved the accelerated vesting of all performance shares. As a result, an additional charge of $3,469,000 which represents the future unamortized expense related to unvested shares at the date the acceleration of vesting occurred, was expensed in 1998.

In addition, the Company recorded a provision of approximately $2.3 million for retirement benefits approved by the compensation committee of the Board of Directors in December of 1998.

11. EQUITY TRANSACTIONS

In November 1995, the Company sold 1,315,500 shares of $2.125 Convertible Exchangeable Preferred Stock, Series A (the "Preferred Stock"). Annual dividends are $2.125 per share and are cumulative. The net proceeds of the $.01 par value stock after underwriters discount and expense was $30,899,000. Each share has a liquidation preference of $25.00, plus accrued and unpaid dividends. Dividends on the Preferred Stock are cumulative from the date of issuance and are payable quarterly, commencing January 15, 1996. The Preferred Stock is convertible at any time, at the option of the holders thereof, unless previously redeemed, into shares of Common Stock of the Company at an initial conversion price of $11 per share of Common Stock, subject to adjustments under certain conditions.

The Preferred Stock is redeemable at any time on or after December 31, 1998, in whole or in part at the option of the Company at a redemption price of $26.488 per share beginning at December 31, 1998 and at premiums declining to the $25.00 liquidation preference by the year 2005 and thereafter, plus accrued and unpaid dividends. The Preferred Stock is also exchangeable, in whole, but not in part, at the option of the Company on or after January 15, 1998 for the Company's 8.5% Convertible Subordinated Debentures due 2010 (the "Debentures") at a rate of $25.00 principal amount of Debentures for each share of Preferred Stock. The Debentures will be convertible into Common Stock of the Company on the same terms as the Preferred Stock and will pay interest semi-annually.

On November 25, 1997, the Company completed a public offering of 1,840,000 shares at a price to the public of $17.00. This offering resulted in the Company receiving cash proceeds of $29,267,000, net of offering costs and underwriting discount. The Company used a portion of the proceeds to repay indebtedness incurred to finance the purchase of Chevron U.S.A. Inc.'s interest in Mobile Block 864 Area (see Note 4) and the remaining proceeds were used to fund a portion of the 1998 capital expenditures budget.

In a December 1998 private transaction, a preferred stockholder elected to convert 59,689 shares of Preferred Stock into 136,867 shares of the Company's Common Stock. Subsequent to December 31, 1998, certain other preferred stockholders, through private transactions, agreed to convert 325,185 shares of Preferred Stock into 772,559 shares of the Company's Common Stock under similar terms.

12. SUPPLEMENTAL OIL AND GAS RESERVE DATA (UNAUDITED)

The Company's proved oil and gas reserves at December 31, 1998, 1997 and 1996 have been estimated by independent petroleum consultants in accordance with guidelines established by the Securities and Exchange Commission ("SEC"). Accordingly, the following reserve estimates are based upon existing economic and operating conditions.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represent estimates only and should not be construed as being exact. In addition, the present values should not be construed as the current market value of the Company's oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

Estimated Reserves

Changes in the estimated net quantities of crude oil and natural gas reserves, all of which are located onshore and offshore in the continental United States, are as follows:

Reserve Quantities

	Years Ended December 31, 1998	1997	1996
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	3,402	3,819	4,766
Revisions to previous estimates	(99)	(151)	(50)
Purchase of reserves in place	162	--	--
Sales of reserves in place	(1,531)	(78)	(312)
Extensions and discoveries	5,274	274	--
Production	(310)	(462)	(585)
End of period	6,898	3,402	3,819
Natural Gas (MMcf):			
Beginning of period	88,738	50,424	29,667
Revisions to previous estimates	(8,631)	(11,174)	(1,688)
Purchase of reserves in place	4,414	52,485	7,391

	1998	1997	1996
Sales of reserves in place	(684)	(164)	(228)
Extensions and discoveries	18,229	10,281	21,551
Production	(14,036)	(13,114)	(6,269)
End of period	88,030	88,738	50,424

Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	2,976	3,385	3,890
End of period	1,774	2,976	3,385
Natural Gas (MMcf):			
Beginning of period	88,010	49,491	20,408
End of period	76,895	88,010	49,491

Standardized Measure

The following tables present the Company's standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves and were computed using reserve valuations based on regulations prescribed by the SEC. These regulations provide that the oil, condensate and gas price structure utilized to project future net cash flows reflects current prices at each date presented and have been escalated only when known and determinable price changes are provided by contract and law. Future production, development and net abandonment costs are based on current costs without escalation. The resulting net future cash flows have been discounted to their present values based on a 10% annual discount factor.

Standardized Measure

	December 31, 1998	1997	1996
	(In thousands)		
Future cash inflows	$256,325	$285,953	$285,727
Future costs -			
Production	(67,192)	(63,709)	(59,584)
Development and net abandonment	(36,581)	(12,984)	(9,989)
Future net inflows before income taxes	152,552	209,260	216,154
Future income taxes	(--)	(32,781)	(49,438)
Future net cash flows	152,552	176,479	166,716
10% discount factor	(52,801)	(48,400)	(36,547)
Standardized measure of discounted future net cash flows	$ 99,751	$128,079	$130,169

Changes in Standardized Measure

	Years Ended December 31, 1998	1997	1996
	(In thousands)		
Standardized measure - beginning of period	$128,079	$130,169	$ 63,764
Sales and transfers, net of production costs	(27,807)	(34,006)	(18,202)
Net change in sales and transfer prices, net of production costs	(33,029)	(66,880)	32,268
Exchange and sale of in place reserves	(4,445)	(2,428)	(877)
Purchases, extensions, discoveries, and improved recovery, net of future production and development costs	24,294	90,550	79,983
Revisions of quantity estimates	(9,409)	(13,751)	(3,907)
Accretions of discount	13,645	16,017	6,376
Net change in income taxes	7,926	21,633	(30,000)
Changes in production rates, timing and other	497	(13,225)	764
Standardized measure - end of period	$ 99,751	$128,079	$130,169

13. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share data)			
1998				
Total revenues	$ 11,492	$ 9,733	$ 9,339	$ 7,154
Total costs and expenses	9,664	8,606	7,919	57,383
Income taxes expense (benefit)	621	380	487	(16,588)
Net income (loss)	1,207	747	933	(33,641)
Net income (loss) per share - basic	.06	.01	.03	(4.27)
Net income (loss) per share - diluted	.06	.01	.03	(4.27)
1997				
Total revenues	$ 12,781	$ 8,758	$ 9,201	$ 12,898
Total costs and expenses	7,366	6,971	7,394	9,270
Income taxes expense	1,733	578	615	1,274
Net income	3,682	1,209	1,192	2,354
Net income per share - basic	.50	.08	.08	.25
Net income per share - diluted	.39	.08	.08	.24

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Directors and Executive Officers of the Company

The Company currently has a Board of Directors composed of seven members. In accordance with the Certificate of Incorporation of the Company, as amended (the "Charter"), the members of the Board of Directors are divided into three classes, Class I, Class II and Class III, and are elected for a full term of office expiring at the third succeeding annual stockholders' meeting following their election to office and when a successor is duly elected and qualified. The terms of office of the Class I, Class II and Class III directors expire at the annual meeting of stockholders in 2001, 1999, and 2000, respectively. The Charter also provides that such classes shall be as nearly equal in number as possible. On February 1, 1999, the Board of Directors approved a resolution increasing the size of the Board from seven to eight directors by providing for an additional Class II director to be effective as of the date of the 1999 Annual Meeting of Stockholders. At December 31, 1998, the directors and executive officers of the Company were as follows:

Name	Age	Company Position Since	Present Company Position
John S. Callon	79	1994	Director (Class II); Chairman of the Board
Fred L. Callon	49	1994	Director (Class III); President; Chief Executive Officer
Dennis W. Christian	52	1994	Director (Class III); Senior Vice President; Chief Operating Officer
Robert A. Stanger	59	1995	Director (Class I)
John C. Wallace	60	1994	Director (Class I)
B. F. Weatherly	55	1994	Director (Class II)
Richard O. Wilson	69	1995	Director (Class I)
John S. Weatherly	47	1994	Senior Vice President; Chief Financial Officer; Treasurer
James O. Bassi	45	1997	Vice President and Controller
Thomas E. Schwager	48	1997	Vice President, Engineering and Operations
H. Michael Tatum	70	1994	Vice President; Secretary
Kathy G. Tilley	53	1996	Vice President, Acquisitions/New Ventures
Stephen F. Woodcock	47	1997	Vice President, Exploration

All of the Directors, other than Messrs. Stanger and Wilson, have served as directors since the Company's inception. Messrs. Stanger and Wilson have served as directors since March 2, 1995.

The following is a brief description of the background and principal occupation of each director and executive officer:

John S. Callon is Chairman of the Board of Directors of the Company and Callon Petroleum Operating Company ("Callon Petroleum Operating"). Effective January 2, 1997, John S. Callon resigned from his position as Chief Executive Officer of the Company, a position he held since 1980. Mr. Callon founded the Company's predecessors in 1950, and has held an executive office with the Company or its predecessors since that time. He has served as a director of the Mid-Continent Oil and Gas Association and as the President of the Association's Mississippi-Alabama Division. He has also served as Vice President for Mississippi of the Independent Petroleum Association of America. He is a member of the American Petroleum Institute. Mr. Callon is the uncle of Fred L. Callon.

Fred L. Callon is President and Chief Executive Officer of the Company and

Callon Petroleum Operating. Prior to January 1997, he was President and Chief Operating Officer of the Company and had held that position with the Company or its predecessors since 1984. He has been employed by the Company or its predecessors since 1976. He graduated from Millsaps College in 1972 and received his M.B.A. degree from the Wharton School of Finance in 1974. Following graduation and until his employment by Callon Petroleum Operating, he was employed by Peat, Marwick, Mitchell & Co., certified public accountants. He is a certified public accountant and is a member of the American Institute of Certified Public Accountants and the Mississippi Society of Certified Public Accountants. He is the nephew of John S. Callon.

Dennis W. Christian is Senior Vice President and Chief Operating Officer for the Company and Callon Petroleum Operating. Prior to January 1997, he was Senior Vice President of Operations and Acquisitions and has held that or similar positions with the Company or its predecessors since 1981. Prior to joining Callon Petroleum Operating, he was resident manager in Stavanger, Norway, for Texas Eastern Transmission Corporation. Mr. Christian received his B.S. degree in petroleum engineering in 1969 from Louisiana Polytechnic Institute. His previous experience includes five years with Chevron U.S.A. Inc.

Robert A. Stanger has been the managing general partner since 1978 of Robert A. Stanger & Company, Inc., a Shrewsbury, New Jersey-based firm engaged in publishing financial material and providing investment banking services to the real estate and oil and gas industries. He is a director of Citizens Utilities, Stamford, Connecticut, a provider of tele-communications, electric, gas, and water services and Electric Lightwaves, Inc., Seattle, Washington, a regional fiber optic telephone company. Previously, Mr. Stanger was Vice President of Merrill Lynch & Co. He received his B.A. degree in economics from Princeton University in 1961. Mr. Stanger is a member of the National Association of Securities Dealers and the New York Society of Security Analysts.

John C. Wallace is a Chartered Accountant having qualified with Coopers and Lybrand in Canada in 1963, after which he joined Baring Brothers & Co., Limited in London, England. For more than the last eleven years, he has served as Chairman of Fred. Olsen Ltd., a London-based corporation which he joined in 1968, and which specializes in the business of shipping and property development. He is a director of Fred. Olsen Energy ASA, a publicly held Norwegian service company engaged in the offshore energy service industry; Harland & Wolff PLC, Belfast, a shipbuilding yard for the offshore oil and gas industry; and Ganger Rolf ASA and Bonheur ASA, Oslo, both publicly-traded shipping companies. He is also an executive officer of NOCO Management, Ltd., a general partner of NOCO Enterprises, L.P. ("NOCO") and of other companies associated with Fred. Olsen Interests.

B. F. Weatherly is a principal of Amerimark Capital Group, Houston, Texas, an investment banking firm and a general partner of CapSource Fund, L. P., Jackson Mississippi, an investment fund. He is an executive officer of NOCO Management Ltd., the general partner of the general partner of NOCO. Prior to September 1996, he was Executive Vice President, Chief Financial Officer and a director of Belmont Constructors, Inc., a Houston, Texas-based industrial contractor associated with Fred. Olsen Interests. He holds a Master of Accountancy degree from University of Mississippi. He has previously been associated with Arthur Andersen LLP, and has served as a Senior Vice President of Weatherford International, Inc. B. F. Weatherly and John S. Weatherly are brothers.

Richard O. Wilson is an Offshore Consultant. In his 42 years of working in offshore drilling and construction, he spent two years with Zapata Offshore and 21 years with Brown & Root, Inc. working in various managerial capacities in the Gulf of Mexico, Venezuela, Trinidad, Brazil, The Netherlands, The United Kingdom and Mexico. He was a director and senior group vice president of Brown & Root, Inc. and senior vice president of Halliburton, Inc. For the last 18 years he has been associated with the Fred. Olsen Interests where he served as Chairman of OGC International PLC, Dolphin A/S, and Dolphin Drilling Ltd. and Belmont Constructors, Inc. Since the sale of OGC International PLC to Halliburton, Inc. in 1997, he has been a consultant to Brown & Root, Inc. on oil and gas projects in Brazil, Bolivia, Mexico and Ecuador. He holds a B.S. degree in civil engineering from Rice University. Mr. Wilson is a Fellow in the American Society of Civil Engineers and a member of the Institute of Petroleum, London, England.

John S. Weatherly is Senior Vice President, Chief Financial Officer and Treasurer for the Company and Callon Petroleum Operating. Prior to April 1996, he was Vice President, Chief Financial Officer and Treasurer of the Company and has held those positions since 1983. Prior to joining Callon Petroleum Operating in August 1980, he was employed by Arthur Andersen LLP as audit manager in the Jackson, Mississippi office. He received his B.B.A. degree in accounting in 1973 and his M.B.A. degree in 1974 from the University of Mississippi. He is a certified public accountant and a member of the American Institute of Certified Public Accountants and the Mississippi Society of Certified Public Accountants. John S. Weatherly and B. F. Weatherly are brothers.

James O. Bassi is Vice President and Controller of the Company and Callon Petroleum Operating. Prior to being appointed to that position in November, 1997, he was Corporate Controller from June, 1997 and prior thereto was Manager of the accounting department for the Company and Callon Petroleum Operating. Mr. Bassi has been employed by the Company and its predecessors for a total of ten years. Prior to his employment by Callon Petroleum Operating, he was employed by Arthur Andersen LLP. He received his B.S. degree in accounting in 1976 from Mississippi State University. He is a member of the American Institute of Certified Public Accountants and the Mississippi Society of Certified Public Accountants.

Thomas E. Schwager is Vice President of Engineering and Operations for the Company and Callon Petroleum Operating. Prior to being appointed to that position in November, 1997, he has held engineering positions with the Company and its predecessors since 1981. Prior to joining the Company, Mr. Schwager held various engineering positions with Exxon Company USA in Louisiana and Texas. He received his B.S. degree in petroleum engineering from Louisiana State University in 1972.

H. Michael Tatum is Vice President and Secretary for the Company and Callon Petroleum Operating and is responsible for management of administrative matters. Mr. Tatum has held this position with the Company or its predecessors since 1976, and has been employed by Callon Petroleum Operating since 1969. He graduated from Southern Methodist University in 1967 and is a member of the American Society of Corporate Secretaries and the Society for Human Resource Management.

Kathy G. Tilley is Vice President of Acquisitions and New Ventures for the Company and Callon Petroleum Operating and has held that position since April 1996. She was employed by Callon Petroleum Operating in December 1989 as Manager of acquisitions and prior thereto, held that or similar positions as a consultant from 1981. Ms. Tilley received her B. A. degree in economics from Louisiana State University in 1967.

Stephen F. Woodcock is Vice President of Exploration for the Company and Callon Petroleum Operating, being appointed to that position in November, 1997. He has been employed by the Company and Callon Petroleum Operating

since 1995, serving as Manager of geology and geophysics. Prior thereto, he was manager of geophysics for CNG Producing Company and division geophysicist for Amoco Production Company. Mr. Woodcock received his Masters degree in geophysics from Oregon State University in 1975.

All officers and directors of the Company are United States citizens, except Mr. Wallace, who is a citizen of Canada.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended ("Exchange Act"), requires the Company's directors and executive officers, and persons who own more than ten percent of a registered class of the Company's equity securities, to file with the Commission and the New York Stock Exchange, initial reports of ownership and reports of changes in ownership of Common Stock and other equity securities of the Company. Officers, directors and greater than ten percent stock-holders are required by the Commission's regulations to furnish the Company with copies of all Section 16(a) forms they filed with the Commission.

To the Company's knowledge, based solely on review of the copies of such reports furnished to the Company and written representations that no other reports were required, during the fiscal year ended December 31, 1998, the Company's officers, directors and greater than ten percent stockholders had complied with all Section 16(a) filing requirements.

ITEMS 11, 12 & 13

For information concerning Item 11 - Executive Compensation, Item 12 - Security Ownership of Certain Beneficial Owners and Management and Item 13 - Certain Relationships and Related Transactions, see the definitive Proxy Statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on April 29, 1999 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

PART IV.

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

(a) 1. The following is an index to the financial statements and financial statement schedules that are filed as part of this Form 10-K on pages 30 through 51.

(a) 2. Schedules other than those listed above are omitted because they are not required, not applicable or the required information is included in the financial statements or notes thereto.

(a) 3. Exhibits:

2. Plan of acquisition, reorganization, arrangement, liquidation or succession*

3. Articles of Incorporation and Bylaws

3.1 Certificate of Incorporation of the Company, as amended (incorporated by reference from Exhibit 3.1 of the Company's Registration Statement on Form S-4, Reg. No. 33-82408)

3.2 Certificate of Merger of Callon Consolidated Partners, L. P. with and into the Company dated September 16, 1994

3.3 Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, Reg. No. 33-82408)

4. Instruments defining the rights of security holders, including indentures

4.1 Specimen stock certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, Reg. No. 33-82408)

4.2 Specimen Preferred Stock Certificate (incorporated by reference from Exhibit 4.2 of the Company's Registration Statement on Form S-1, Reg. No. 33-96700)

4.3 Designation for Series A Preferred Stock (incorporated by reference from Exhibit 4.3 of the Company's Registration Statement on Form S-1, Reg. No. 33-96700)

4.4 Indenture for Convertible Debentures (incorporated by reference from Exhibit 4.4 of the Company's Registration Statement on Form S-1, Reg. No. 33-96700)

4.5 Certificate of Correction on Designation of Series A Preferred Stock (incorporated by reference from Exhibit 4.4 of the Company's Registration Statement on Form S-1/A filed November 22, 1996, Reg. No. 333-15501)

4.6 Form of Note Indenture (incorporated by reference from Exhibit 4.6 of the Company's Registration Statement on Form S-1/A filed November 22, 1996, Reg. No. 333-15501)

9. Voting trust agreement

9.1 Stockholders' Agreement dated September 16, 1994 among the Company, the Callon Stockholders and NOCO Enterprises, L. P. (incorporated by reference from Exhibit 9.1 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

10. Material contracts

10.1 Registration Rights Agreement dated September 16, 1994 between the Company and NOCO Enterprises, L. P. (incorporated by reference from Exhibit 10.2 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

10.2 Registration Rights Agreement dated September 16, 1994 between the Company and Callon Stockholders (incorporated by reference from Exhibit 10.3 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

10.3 Callon Petroleum Company 1994 Stock Incentive Plan (incorporated by reference from Exhibit 10.5 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

10.4 Credit Agreement dated October 14, 1994 by and between the Company, Callon Petroleum Operating Company and Internationale Nederlanden (U.S.) Capital Corporation (incorporated by reference from Exhibit 99.1 of the Company's Report on Form

10-Q for the quarter ended September 30, 1994)

10.5 Third Amendment dated February 22, 1996, to Credit Agreement by and among Callon Petroleum Operating Company, Callon Petroleum Company and Internationale Nederlanden (U. S.) Capital Corporation (incorporated by reference from Exhibit 10.9 of the Company's Form 10-K for the fiscal year ended December 31, 1995)

10.6 Consulting Agreement between the Company and John S. Callon dated June 19, 1996 (incorporated by reference from Exhibit 10.10 of the Company's Registration Statement on Form S-1, filed November 5, 1996, Reg. No. 333-15501)

10.7 Employment Agreement effective September 1, 1996, between the Company and Fred L. Callon (incorporated by reference from Exhibit 10.4 of the Company's Registration Statement on Form S-1/A, filed November 14, 1996, Reg. No. 333-15501)

10.8 Employment Agreement effective September 1, 1996, between the Company and Dennis W. Christian (incorporated by reference from Exhibit 10.7 of the Company's Registration Statement on Form S-1/A, filed November 14, 1996, Reg. No. 333-15501)

10.9 Employment Agreement effective September 1, 1996, between the Company and John S. Weatherly (incorporated by reference from Exhibit 10.8 of the Company's Registration Statement on Form S-1/A, filed November 14, 1996, Reg. No. 333-15501)

10.10 Callon Petroleum Company's Amended 1996 Stock Incentive Plan (incorporated by reference from Exhibit 4.4 of the Post-Effective Amendment No. 1 to the Company's Registration Statement on Form S-8, filed February 5, 1999, Reg. No. 333-29537)

11. Statement re computation of per sharing earnings*

12. Statements re computation of ratios*

13. Annual Report to security holders, Form 10-Q or quarterly reports*

16. Letter re change in certifying accountant*

18. Letter re change in accounting principles*

21. Subsidiaries of the Company

21.1 Subsidiaries of the Company (incorporated by reference from Exhibit 21.1 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

22. Published report regarding matters submitted to vote of security holders*

23. Consents of Experts and Counsel

23.1 Consent of Arthur Andersen LLP

24. Power of attorney*

27. Financial data schedule

A financial data schedule for the year ended December 31, 1998 (EX-27) was filed electronically along with the Form 10-K.

99. Additional Exhibits*

- ----------
*Inapplicable to this filing.

(b) Reports on Form 8-K.

None

SIGNATURES

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

CALLON PETROLEUM COMPANY

Date: March 29, 1999 ____________/s/ Fred L. Callon_______________________
Fred L. Callon (principal executive officer, director)

Date: March 29, 1999 ____________/s/ John S. Weatherly____________________
John S. Weatherly (principal financial officer)

Date: March 29, 1999 ____________/s/ James O. Bassi______________________
James O. Bassi (principal accounting officer)

Date: March 29, 1999 ___________/s/ John S. Callon________________________
John S. Callon (director)

Date: March 29, 1999 ___________/s/ Dennis W. Christian___________________
Dennis W. Christian (director)

Date: March 29, 1999 ___________/s/ B. F. Weatherly_______________________
B. F. Weatherly (director)

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

CALLON PETROLEUM COMPANY

Date: March 29, 1999 By: ___/s/ John S. Weatherly_____________
John S. Weatherly, Senior Vice President,
Chief Financial Officer and Treasurer

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Exhibit 23.1

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation by reference of our report dated February 19, 1999, included in this Form 10-K, into Callon Petroleum Company's previously filed Registration Statements on Forms S-8 (File Nos. 33-90410, 333-29537 and 333-29529).

Arthur Andersen LLP

New Orleans, Louisiana
March 29, 1999