SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 1999

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 NATCHEZ, MISSISSIPPI 39120	(601) 442-1601
(Address of Principal Executive Offices)(Zip Code)	(Registrant's telephone number including area 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 $145,472,700 as of March 13, 2000 (based on the last reported sale price of such stock on the New York Stock Exchange).

As of March 13, 2000, there were 12,264,101 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, 1999) relating to the Annual Meeting of Stockholders to be held on May 9, 2000, 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 (the "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 primarily 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.

Beginning in 1989, 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 four years, the Company has also placed emphasis on the acquisition of acreage with exploration and development drilling opportunities. The Company acquired an infrastructure of production platforms, gathering systems and pipelines to minimize development expenditures of these drilling opportunities. The Company also joined with other industry partners, primarily Murphy Exploration and Production, Inc., ("Murphy") to explore federal offshore blocks acquired in the Gulf of Mexico. The Company currently has 65 federal offshore blocks in inventory. During this period, Callon has drilled 20 productive wells and 10 dry holes for a total of 30 wells and a success rate of 67%. These 20 productive wells include three onshore, 14 in the Gulf of Mexico shelf area and three in the deepwater region of the Gulf. During 1999, seven of these productive wells contributed 135 billion cubic feet of natural gas equivalent ("Bcfe") of reserve additions. These additions from the drill bit contributed to a net reserve replacement cost of $0.46 per million cubic feet of natural gas equivalent ("Mcfe").

The major focus of the Company's future operations 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 goals are to increase reserves, production, cash flow and earnings at low reserve replacement costs and it seeks to achieve these goals through the following strategies:

- Assemble and explore a balanced portfolio of projects in the Gulf of Mexico composed of:

  -Controlling working interest in projects with low exploration risk and low drilling and completion costs targeting reserve deposits of between 3 and 10 billion cubic feet of natural gas ("Bcf") in the shallow Miocene area at well depths of less than 4,000 feet;

-Significant working interests in projects with moderate exploration risk and higher drilling and completion costs targeting reserve deposits of between 10 and 100 Bcfe in the OCS area at well depths of between 7,000 and 17,000 feet; and

-Smaller working interests in projects with high exploration risk and high drilling and completion costs targeting large reserve deposits in the deep water area of the Gulf of Mexico.

- o Acquire at low costs, additional working interest, gathering systems, pipelines, production facilities and other infrastructure in areas in which it operates. Ownership of these facilities enables the Company to reduce the costs of completing wells and to control the timing of the development of our properties.

- o Utilize the latest available technology. The Company's geoscientists and petroleum engineers have developed an expertise with advanced technologies, including 3-D seismic interpretation and computer-aided exploration.

- o Maintain financial flexibility. The Company strives to maintain a substantial unused borrowing capacity under its bank credit facility by periodically refinancing our bank debt in the capital markets by issuing both debt and equity securities.

EXPLORATION AND DEVELOPMENT ACTIVITIES

GULF OF MEXICO DEEPWATER

Habanero, Garden Banks Block 341

During February 1999 the initial test well on the Company's Habanero prospect 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 was the second deepwater success for the Company. 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.

Medusa, Mississippi Canyon 538/582

During September 1999 the initial test well on the Company's Medusa prospect encountered over 120 feet of net pay. Located in 2,100 feet of water, the well was drilled to a measured depth of 16,241 feet. Delineation drilling accomplished by sidetracking from the original well bore encountered an additional 200 feet of pay in separate fault blocks. A second well was spud in January 2000 to test updip limits in one objective and further delineate a deeper objective. Callon owns a 15% working interest in the well. It is

operated by Murphy, which owns a 60% working interest, with the remaining working interest being owned by British-Borneo Petroleum, Inc.

Entrada, Garden Banks 782/826/827

The test well, which will be drilled to a true vertical depth of 15,500 feet, will be located in 4,690 feet of water and is scheduled to be spud during the second quarter. The Company owns a 20 percent working interest and Vastar Resources, Inc. is the operator.

GULF OF MEXICO SHELF

South Marsh Island Block 261 #1

The initial well was drilled to 8,000 feet and encountered 110 feet of net natural gas pay in two sandstone formations between 5,400 feet and 5,800 feet. The well tested at over 10 million cubic feet of natural gas ("MMcf") per day from both the upper and lower perforations. Callon owns a 100% working interest in this discovery and anticipates placing the well on production through facilities on an adjacent block before the end of the second quarter of 2000.

South Marsh Island Block 261 #2

A second test well was spud in December 1999 and encountered 100 feet of net natural gas in five pay sands. However, in January, the well blew out and had to be plugged. The South Marsh Island Block 261 #3, a replacement well, is currently drilling at an adjacent location and the company owns a 100% working interest.

East Cameron Block 275

Drilled to a measured depth of 10, 746 feet, the company's test well encountered net natural gas pay of 160 feet (TVD) in five intervals between 5,800 feet and 10,500 feet. The well tested at a combined rate of 18.1 million cubic feet of natural gas equivalent ("MMcfe") per day from two zones. Callon owns a 100% working interest in the well and anticipates placing the well on production through facilities on an adjacent block at the beginning of the second quarter 2000.

Snapper, High Island Block A-494

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. The well was brought on line in July 1999 and is currently producing 8.8 MMcf per day. Callon owns a 50% working interest in the well and the operator, PetroQuest Energy, Inc. holds 42%.

RECENT DEVELOPMENTS

The Company had four exploration wells that were in progress at the end of 1999 and two wells that were drilled subsequent to year-end 1999. Four of these six wells were determined to be non-commercial during the first quarter of 2000. In the aggregate, the Company's net costs for the four unsuccessful wells were approximately $12.1 million.

RECENT ACQUISITIONS

In December 1999, Callon purchased from Santos USA Corporation an additional 20% working interest in the Boomslang deepwater discovery on Ewing Bank Block 994 for $7.3 million. This brought Callon's total working interest in the well to 55%.

In June 1999, the Company acquired various working interests in the Mobile Block 864 Area in which the Company already owned an interest. Concurrent with this acquisition, the seller received a volumetric production payment, valued at approximately $14.8 million, from production attributable to a portion of the

Company's interest in the area over a 39-month period. Under the terms of the sale, the Company is obligated to deliver the production volumes free and clear of royalties, lease operating expenses, production taxes and all capital costs.

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. Beginning in 1997 and continuing through early 1999, the prices we received for production generally declined, especially for oil. Oil prices have recently increased significantly, but remain volatile. 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.

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 several 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 oil and 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 barrel "(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 estimates include volumes of approximately 5.8 Bcf, $12.1 million of future cash inflows and $10.7 million of discounted cash flows attributable to a volumetric production payment.

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.

OPERATIONS BY THIRD PARTIES

The Company does not operate all of its properties and has limited influence over the operations of some of these properties, particularly the deepwater projects. This lack of control could result in the operator initiating exploration or development activities on a faster or slower pace than the Company prefers. If the operator proposes to expand drilling or development projects greater than the Company has funds for, the Company may be unable to participate in the project or share in the revenues. Also if the operator refuses to initiate a project, the Company may be unable to pursue the project, which could reduce the value of the property.

DEEPWATER DRILLING AND OPERATIONS

Drilling operations in the deepwater area are by their nature more difficult and costly than drilling operations in shallower water. Deepwater exploration requires the application of more advanced drilling technologies, involving a higher risk of technological failure and usually resulting in significantly higher drilling costs. Deepwater wells are completed using subsea completion techniques that require substantial time and the use of advanced remote installation equipment. These operations involve a high risk of mechanical difficulties and equipment failures that could result in significant cost overruns.

In the deepwater area, the time required to commence production following a discovery is much longer than in shallow waters and on-shore. All of the Company's deepwater discoveries and prospects will require the construction of expensive production facilities and pipelines prior to the beginning of production. The costs and timing of the construction of these facilities cannot be estimated with certainty, and the accuracy of such estimates will be affected by a number of factors beyond our control, including decisions made by the operators of our deepwater wells, the availability of materials necessary to construct the facilities, proximity of our discoveries to pipelines and the price of oil and natural gas. Delays and cost overruns in the commencement of production will affect the value of the deepwater prospects and the discounted present value of reserves attributable to those prospects.

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 2 gross (.3 net) development wells and 13 gross (5.2 net) exploratory wells through fiscal 2000. The estimated cost, net to the Company, to drill and complete these wells is approximately $75 million with dry hole costs of approximately $36 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 forecast for 2000 is approximately $85 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, lack of drilling success, operating difficulties or declines in reserves, the Company may have limited ability to repay debt and 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, 1999, 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 for 2000 are for average gas volumes of 231,250 Mcf per month beginning in February 2000 through September, 2000 at (on a weighted average) a ceiling price of $2.80 and floor price of $2.56. The Company had no open oil hedging contracts at December 31, 1999.

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 94 employees as of December 31, 1999, none of who are currently represented by a union. The Company considers itself to have good relations with its employees. The Company employs six petroleum engineers and five 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.

The FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000 concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

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 ("MMS") or other appropriate federal or state agencies.

The Company's OCS leases in federal waters are administered by the MMS and require compliance with detailed MMS regulations and orders. The MMS has promulgated regulations implementing restrictions on various production-related activities, including restricting the flaring or venting of natural gas. Under certain circumstances, the MMS may require and Company operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect the Company's financial condition and operations. On March 15, 2000, the MMS issued a final rule effective June 1, 2000 which amends its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. Among other matters, this rule amends the valuation procedure for the sale of federal royalty oil by eliminating posted prices as a measure of value and relying instead on arm's length sales prices and spot market prices as market value indicators. Because the Company sells its production in the spot market and therefore pays royalties on production from federal leases, it is not anticipated that this final rule will have any substantial impact on the Company.

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. Certain amendments to the OPA that were enacted in 1996 require owners and operators of offshore facilities that have a worst case oil spill potential of more than 1,000 barrels to demonstrate financial responsibility in amounts ranging from $10 million in specified state waters and $35 million in federal OCS waters, with higher amounts, up to $150 million based upon worst case oil-spill discharge volume calculations. The Company believes that it currently has established adequate proof of financial responsibility for its offshore facilities.

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 would 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, 1999, the Company's estimated proved reserves totaled 23.8 million barrels of oil ("MBbl") and 116.4 Bcf 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 $296.5 million. Gas constitutes approximately 45% of the Company's total estimated proved reserves and approximately 26% of the Company's reserves are proved producing reserves.

SIGNIFICANT PROPERTIES

The following table shows discounted cash flows and estimated net proved oil and gas reserves by major field for the Company's ten largest fields and for all other properties combined at December 31, 1999.

<TABLE>
<CAPTION>

PROVED RESERVES BY FOCUS AREA:	PRIMARY OPERATOR(S)	DISCOUNTED CASH FLOW ($000)(a)(b)	PERCENT TOTAL DISCOUNTED CASH FLOW	ESTIMATED NET PROVED RESERVES (MBBLS)(b)	RESERVES (MMcf)(b)	RESERVES (MMcfe)(b)
<S>	<C>	<C>	<C>	<C>	<C>	<C>
GULF OF MEXICO DEEPWATER:						
Ewing Bank Block 994 "Boomslang"	Murphy	$ 53,507	18.1%	7,230	13,015	56,395
Mississippi Canyon 538/582 "Medusa"	Murphy	65,302	22.0%	8,835	8,764	61,774
Garden Banks Block 341 "Habanero"	Shell	66,993	22.6%	6,393	12,547	50,902
TOTAL DEEPWATER		185,802	62.7%	22,458	34,326	169,071
GULF OF MEXICO SHELF:						
Mobile Block 864 Area	Callon	55,545	18.7%	0	48,897	48,897
South Marsh Island 261	Callon	16,070	5.4%	32	10,768	10,962
East Cameron 275	Callon	4,865	1.6%	27	5,325	5,485
Main Pass Block 26/SL 15827	Callon	5,775	2.0%	123	3,024	3,761
High Island Block A-494 "Snapper"	PetroQuest	3,217	1.1%	0	2,828	2,828
Eugene Island Block 335	Murphy	3,212	1.1%	48	1,574	1,862
Other	Callon	1,282	0.4%	69	3,114	3,527
TOTAL SHELF		89,966	30.3%	299	75,530	77,322
ONSHORE:						
Big Escambia Creek	Exxon	7,785	2.6%	657	1,703	5,647
Other	Various	12,960	4.4%	420	4,876	7,401
TOTAL ONSHORE		20,745	7.0%	1,077	6,579	13,048
TOTAL		$296,513	100.0%	23,834	116,435	259,441

</TABLE>

(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, 1999, as set forth in the Company's independent reserve reports prepared by Huddleston & Co., Inc. of Houston, Texas.

(b) The estimates include volumes of approximately 5.8 Bcf, $12.1 million of future cash inflows and $10.7 million of discounted cash flows attributable to a volumetric production payment.

GULF OF MEXICO DEEPWATER

Boomslang, Ewing Bank Block 994

Located in 900 feet of water, the Boomslang prospect was drilled to a total depth of 12,955 feet and encountered 185 net feet of oil pay in three separate zones. In December 1999, Callon purchased from Santos USA Corporation an additional 20% working interest in the Boomslang deepwater discovery on Ewing Bank Block 994 for $7.3 million. This brought Callon's total working interest in the well to 55%. Estimated net proved reserves at December 31, 1999 were 7.2 million barrels of oil and 13.0 Bcf of natural gas with a discounted cash flow of $53.5 million.

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.

Medusa, Mississippi Canyon Block 538/582

The initial well encountered two intervals with over 120 feet of total pay after being drilling to a measured depth of 16,241 feet. The test well encountered 59 true vertical feet of pay in the T1 objective in Fault Block A and 61 true vertical feet of pay in the T4 sand. A sidetrack well, testing the extent of the discovery, encountered 110 true vertical feet of pay in the T1 objective sand in Fault Block B. An additional sidetrack well was drilled to test the downdip limits of the T1 pay sand in Fault Block B and encountered 90 feet (True Vertical Depth) of oil pay. A delineation well was spud in January and is designed to test the updip limits of the T1 pay sand in Fault Block A. This latest well will drill deeper to further delineate the T4 objective, which was discovered by the original well. The Prospect lies in approximately 2,100 feet of water and the company owns a 15% working interest with Murphy, the operator owning 60% and British-Borneo Petroleum, Inc. owning the remaining 25%. This was Callon's third consecutive deepwater discovery. Estimated net proved reserves at December 31, 1999 were 8.8 million barrels of oil and 8.8 Bcf of natural gas with a discounted cash flow of $65.3 million.

Habanero, Garden Banks Block 341

During February 1999 the initial test well on the Company's Habanero prospect 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 was the second deepwater success for Callon. 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. Estimated net proved reserves at December 31, 1999 were 6.4 million barrels of oil and 12.5 Bcf of natural gas with a discounted cash flow of $67.0 million.

GULF OF MEXICO SHELF

Mobile Block 864 Area

The Mobile Block 864 Area is located offshore Alabama in the federal waters of the OCS. The Company consummated five acquisitions in this area for a total of $63.8 million. In total, the Company has acquired an average 81.6% working interest in seven blocks, a 66.4% working interest in the Mobile Block 864 Area unit and the unit production facilities, and a 100% working interest in three producing wells. The Company was appointed operator of the Mobile Block 864 unit and three other wells. Estimated net proved reserves at December 31, 1999 were 48.9 Bcf and a discounted cash flow value of $55.5 million. Net average daily production during 1999 was 15.2 MMcf per day.

South Marsh Island Block 261 #1

The initial well was drilled to 8,000 feet and encountered 110 feet of net natural gas pay in two sandstone formations between 5,400 feet and 5,800 feet. The Company separately flow-tested each pay zone. The upper completion tested at 10.3 million cubic feet of natural gas per day (MMcf/d) from perforations at 5,410 feet through 5,450 feet on a 25/64-inch choke with flowing tubing pressure of 2,852 pounds per

square inch (Psi). The lower completion tested at 10.1 MMcf/d from perforations at 5,678 feet through 5,714 feet on a 24/64-inch choke with flowing tubing pressure of 3,004 Psi. The single selective completion will allow production from either of the two pay zones through 3 1/2-inch production tubing. Callon owns a 100% working interest in this discovery and anticipates placing the well on production through facilities on an adjacent block before the end of the second quarter of 2000. Estimated net proved reserves at December 31, 1999 were 11.0 Bcfe and a discounted cash flow value of $16.1 million.

East Cameron Block 275

Drilled to a measured depth of 10,746 feet, the Company's test well encountered net natural gas pay of 160 feet (TVD) in five intervals between 5,800 feet and 10,500 feet. The well tested at a combined rate of 18.1 million cubic feet of natural gas equivalent (MMcfe) per day from two zones. From lower perforations between 10,461 feet through 10,482 feet the well tested at 4.6 million cubic feet of natural gas (MMcf) and 240 barrels of condensate (Bc) per day on a 20/64-inch choke with flowing tubing pressure of 2,605 pounds per square inch (Psi). It tested at 8.9 MMcf and 528 Bc per day from upper perforations between 10,384 feet and 10,418 feet on a 22/64-inch choke with flowing tubing pressure of 3,315 Psi. The well is scheduled to begin production at the beginning of the second quarter 2000. Callon owns a 100% working interest in the well. Estimated net proved reserves at December 31, 1999 were 5.5 Bcfe and a discounted cash flow value of $4.9 million.

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. Estimated net proved reserves at December 31, 1999 were 3.0 Bcf of natural gas and 123 MBbls of condensate with a discounted cash flow of $5.8 million.

Snapper, High Island Block A-494

In February 1999, the #C-1 well reached a total depth of 8,800 and encountered 207 feet of gross gas pay with 80 feet of net natural gas pay in the objective Cris. S. sandstone formation. The well was brought on line in July 1999 and is currently producing 8.8 million cubic feet of natural gas per day (MMcf/d). Callon owns a 50% working interest in the well and the operator, PetroQuest Energy, Inc. holds 42%. Estimated net proved reserves at December 31, 1999 were 2.8 Bcfe with a discounted cash flow value of $3.2 million.

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. Production commenced during the first quarter of 1999 and the wells are currently producing at a rate of 16.3 MMcf and 643 Bbls per day. Callon owns a 20% working interest in the wells. Estimated net proved reserves at December 31, 1999 were 48 MBbls of oil and 1.6 Bcf of natural gas.

ONSHORE

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 1999 was 2.6 MBbls of condensate, 1.1 MBbls of natural gas liquids, 6.7 MMcf of residue natural gas and 312 long tons of sulfur. These wells are producing from the Smackover formation at depths ranging from 15,100 to 15,600 feet.

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.

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	1999(a)	1998	1997
<S>	<C>	<C>	<C>
	(IN THOUSANDS)		
Proved developed:			
Oil (Bbls)	1,376	2,079	2,976
Gas (Mcf)	82,109	76,895	88,010
Proved undeveloped:			
Oil (Bbls)	22,458	4,819	426
Gas (Mcf)	34,326	11,135	728
Total proved:			
Oil (Bbls)	23,834	6,898	3,402
Gas (Mcf)	116,435	88,030	88,738
Estimated pre-tax future net cash flows	$528,659	$152,552	$209,264
Discounted cash flows	$296,513	$99,751	$136,448

</TABLE>

(a) The estimates include volumes of approximately 5.8 Bcf, $12.1 million of future cash inflows and $10.7 million of discounted cash flows attributable to a volumetric production payment.

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.

<TABLE>
<CAPTION>

	Years Ended December 31,					
	1999		1998		1997	
	Gross	Net	Gross	Net	Gross	Net
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Development:						
Oil	--	--	2	.40	--	--
Gas	--	--	--	--	1	1.00
Non-productive	--	--	--	--	--	--
	--	--	2	.40	1	1.00
Exploration:						
Oil	2	0.26	1	.35	--	--
Gas	5	3.79	3	2.14	2	1.20
Non-productive	2	1.20	2	1.25	6	1.91
Total	9	5.25	6	3.74	8	3.11

</TABLE>

The Company owned working and royalty interests in approximately 261 gross (8.2 net) producing oil and 298 gross (27.6 net) producing gas wells as of December 31, 1999. 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, 1999, the Company had two exploratory gas wells and two exploratory oil wells 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, 1999.

<TABLE>
<CAPTION>

LEASEHOLD ACREAGE	
DEVELOPED	UNDEVELOPED

LOCATION	GROSS	NET	GROSS	NET
--------	-----	---	-----	---
<S>	<C>	<C>	<C>	<C>
Alabama	12,813	12,685	64	64
Louisiana	10,462	9,376	11,016	6,928
Other States	888	416	1,478	1,169
Federal Waters	118,331	84,874	333,869	84,145
	-------	-------	-------	------
Total	142,494	107,351	346,427	92,306
	=======	=======	=======	======

</TABLE>

As of December 31, 1999, 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, 1999, Dynegy Marketing & Trade, Adams Resources Marketing, Ltd., and Columbia Energy Services purchased 12%, 16%, and 29% 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, MP164/165, MB864, EI 335, HI A494, and MB952/955 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 1999.

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
1998:		
First quarter	$17.125	$15.000
Second quarter	18.375	14.000
Third quarter	14.875	7.875
Fourth quarter	14.000	10.875
1999:		
First quarter	$11.875	$ 8.875
Second quarter	11.250	9.875
Third quarter	15.375	10.000
Fourth quarter	15.375	11.625

As of March 13, 2000, there were approximately 6,791 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 and the terms of the Company's outstanding Subordinated Debt restrict 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, 1999 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,				
	1999	1998	1997	1996	1995
<S>	<C>	<C>	<C>	<C>	<C>
STATEMENT OF OPERATIONS DATA:					
Revenues:					
Oil and gas sales	$ 37,140	$ 35,624	$ 42,130	$ 25,764	$ 23,210
Interest and other	1,853	2,094	1,508	946	627
Total revenues	38,993	37,718	43,638	26,710	23,837
Costs and expenses:					
Lease operating expenses	7,536	7,817	8,123	7,562	6,732
Depreciation, depletion and amortization	16,727	19,284	16,488	9,832	10,376
General and administrative	4,575	5,285	4,433	3,495	3,880
Interest	6,175	1,925	1,957	313	1,794
Accelerated vesting and retirement benefits	--	5,761	--	--	--
Impairment of oil and gas properties	--	43,500	--	--	--
Total costs and expenses	35,013	83,572	31,001	21,202	22,782
Income (loss) from operations	3,980	(45,854)	12,637	5,508	1,055
Income tax expense (benefit)	1,353	(15,100)	4,200	50	--
Net income (loss)	2,627	(30,754)	8,437	5,458	1,055
Preferred stock dividends	2,497	2,779	2,795	2,795	256
Net income (loss) available to common shares	$ 130	$(33,533)	$ 5,642	$ 2,663	$ 799
Net income (loss) per common share:					
Basic	$ .01	$ (4.17)	$ .91	$ .46	$ .14
Diluted	$ .01	$ (4.17)	$ .88	$ .45	$ .14
Shares used in computing net income (loss) per common share:					
Basic	8,976	8,034	6,194	5,835	5,755
Diluted	9,075	8,034	6,422	5,952	5,755
Balance Sheet Data (end of period):					
Oil and gas properties, net	$194,365	$141,905	$150,494	$ 82,489	$ 57,765
Total assets	$259,877	$181,652	$190,421	$118,520	$ 83,867
Long-term debt, less current portion	$100,250	$ 78,250	$ 60,250	$ 24,250	$ 100
Stockholders' equity	$124,380	$ 84,484	$113,701	$ 77,864	$ 75,129

</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 exploration, development and acquisition 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.

Proved oil and gas reserves increased significantly to 259 billion cubic feet of natural gas equivalent (Bcfe). This represents an increase of 101% over previous year-end 1998 proved reserves of 129 Bcfe. This increase in 1999 is primarily due to results of drilling activity in the deepwater areas of the Gulf of Mexico, along with drilling successes on the Outer Continental Shelf in the same region. Proved Undeveloped Reserves increased 322% over 1998 amounts due primarily to deepwater exploration successes at Habanero and Medusa together with additional interests acquired in 1999 at Ewing Bank Block 994, which was discovered in 1998. Development of these significant reserve additions will require substantial capital.

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 operation. 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 89% of the projected 2000 production and 45% 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, faced 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.

Total costs incurred for consultants, software and hardware applications for the Year 2000 project were less than $200,000. The Company did not experience any disruption of operations from the Year 2000 threat.

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 increased during 1999 by $28.4 million. Cash provided from

operating activities during 1999 totaled $21.2 million. The Company completed a

Common Stock offering which netted the Company $41.1 million in November 1999. An additional $22 million (net) was borrowed and cash capital expenditures for the twelve-month period totaled $51.7 million. $2.3 million was paid as dividends on preferred stock. Average debt outstanding was $96.9 million during 1999 compared to $64.8 million in 1998. At December 31, 1999, the Company had working capital of $20.5 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 currently provides for a $30 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, 1999, the availability on this Credit Facility was $29.9 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.

On July 15, 1999 the Company completed its sale of $40 million of Senior Subordinated Notes due 2004 at 10.25%. The net proceeds of approximately $38.2 million were used to pay down the Credit Facility at that time. These notes are not entitled to any mandatory sinking fund payments and are subject to redemption at the Company's option at par plus unpaid interest at any time after March 15, 2001. The notes are subject to a change of control clause that obligates the Company to repurchase the 10.25% notes for 101% of par should a change of control occur. Interest is paid quarterly beginning September 15, 1999.

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, 1999.

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 expenses was $30,899,000. Each share has a liquidation preference of $25, 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 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 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.

In November of 1999, the Company sold 3,680,000 shares of Common Stock in a public offering at a price to the public of $11.875 per share. Cash proceeds received by the Company were $41.1 million net of underwriting discount and offering costs. The proceeds from the stock offering were used to pay the outstanding balance of the Credit Facility and to fund, together with internally generated cash flows from operations, the remaining portion of its 1999 and part of the 2000 capital expenditure budget.

Gross capital expenditures for 1999 totaled $68.9 million which included $24.1 million (of this amount, $14.8 million was financed by a volumetric production payment) for the acquisition of oil and gas properties, $43.0 million for property development and drilling activities on new and previously existing properties and $1.8 million for acquisition of oil and gas properties not yet evaluated. The Company's plans for 2000 include capital expenditures of approximately $85 million, primarily in the Gulf of Mexico. Projected cash flows from operations, cash on hand 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 for 2000 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, 1999.

<TABLE>
<CAPTION>

	DECEMBER 31,		
	1999(a)	1998	1997
Production:			
Oil (MBbls)	330	310	462
Gas (MMcf)	14,606	14,036	13,114
Total production (MMcfe)	16,589	15,894	15,887
Average daily production (MMcfe)	45.5	43.5	43.5
Average sales price:			
Oil (per Bbl)	$ 12.16	$ 12.41	$ 18.63
Gas (per Mcf)	$ 2.27	$ 2.26	$ 2.56
Total production (per Mcfe)	$ 2.24	$ 2.24	$ 2.65
Average costs (per Mcfe):			
Lease operating expenses (excluding severance taxes)	$ .39	$ .44	$ .42
Severance taxes	$ .07	$ .06	$ .09
Depletion	$ .99	$ 1.19	$ 1.02
General and administrative (net of management fees)	$ .28	$ .33	$ .28

</TABLE>

(a) Includes volumes of 1,300 MMcf at an average price of $2.08 per Mcf associated with a volumetric production payment.

COMPARISON OF RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 1999 AND 1998

OIL AND GAS REVENUES

Oil and gas revenues for 1999 were $37.1 million, a 4% increase from the 1998 amount of $35.6 million. Similarly, 1999 oil and gas production of 16,600 MMcfe increased by 4% over the 1998 amount of 15,900 MMcfe.

Oil production increased from 310,000 barrels in 1998 to 330,000 barrels in 1999 but the average sales price declined from $12.41 in 1998 to $12.16 in 1999. As a result, oil revenues went from $3.8 million in 1998 to $4.0 million in 1999. The increase in oil production was primarily from Main Pass 26 and Eugene Island 335 offset by the loss of production in 1999 from the Black Bay Field, which was sold in 1998.

Gas revenues for 1999 were $33.1 million based on sales of 14.6 Bcf at an average sales price of $2.27 per Mcf. For 1998, gas revenues were $31.8 million based on production of 14 Bcf sold at an average sales price of $2.26 per Mcf. When compared to 1998, the Company in 1999 added gas production from new discoveries at Main Pass 26 and Eugene Island 335 but has experienced reduced production from several Shallow Miocene properties which normally have steep decline curves. Except for the increase at Main Pass 31, which was the result of a recompletion, other properties continue to experience normal and expected declines.

The following table summarizes oil and gas production from the Company's major producing properties for the years 1999 and 1998:

<TABLE>
<CAPTION>

	OIL PRODUCTION (Bbls)		GAS PRODUCTION (Mcf)	
	1999	1998	1999	1998
<S>	<C>	<C>	<C>	<C>
Mobile Block 864 Area	--	--	5,550,700	5,355,200
Chandeleur Block 40	--	--	804,600	2,443,400
Main Pass 163 Area	--	--	1,946,400	3,007,100

</TABLE>

<TABLE>

<S>	<C>	<C>	<C>	<C>
Main Pass 26	46,700	500	823,600	--
Eugene Island 335	24,700	--	1,089,600	--
Main Pass 31	34,300	39,400	1,148,200	1,045,300
Main Pass 164/165	--	--	--	--
North Dauphin Island Field	--	--	479,200	1,012,600
High Island Block A-494	--	--	1,130,900	--
Escambia Minerals	144,400	152,700	257,000	269,600
Other Properties	80,300	117,100	1,375,700	902,800
Total	330,400	309,700	14,605,900	14,036,000

</TABLE>

LEASE OPERATING EXPENSES AND SEVERANCE TAXES

Lease operating expenses, including severance taxes, decreased from $7.8 million in 1998 to $7.5 million in 1999 as a result of a decrease in operating expenses in the Main Pass 163 Area and the North Dauphin Island Field as well as the sale of the Black Bay Field in 1998. This decline was offset by the Snapper, Main Pass 36, Main Pass 26 and Kemah properties which began operations in 1999.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation, depletion and amortization decreased due to the combined effect of the net increase in proved reserves during 1999 (primarily in the fourth quarter of 1999), the level of finding costs attributable to reserves added in 1999 and the reduction of the full cost pool due to an impairment of oil and gas properties at December 31, 1998. Total charges decreased from $19.3 million, or $1.21 per Mcfe in 1998, to $16.7 million, or $1.01 per Mcfe in 1999.

GENERAL AND ADMINISTRATIVE

General and administrative expenses for 1999 were $4.6 million, or $.28 per Mcfe, compared to $5.3 million, or $.33 per Mcfe, in 1998. This 13% decrease is primarily due to a reduction of staff in 1999 along with an increase in overhead allocable to employees directly engaged in the acquisition, exploration and development of oil and gas properties in 1999.

INTEREST EXPENSE

Interest expense for 1999 and 1998 was $6.2 million and $1.9 million, respectively. This increase is a result of a decrease in interest capitalized on unevaluated oil and gas properties and the increase in interest rates and in average debt outstanding in 1999 versus 1998. This average debt outstanding increase is directly related to the Senior Subordinated Notes issued in July 1999 and the Credit Facility borrowings during the year. The Common Stock offering completed in November 1999 reduced Credit Facility debt at the end of 1999.

INCOME TAXES

The Company's 1999 results include a deferred income tax expense of $1.4 million. The Company has evaluated the realizability of the deferred income tax asset in light of its reserve quantity estimates, its long-

term outlook for oil and gas prices and its expected level of future revenues and 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, 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 reliability 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.

ITEM 7A.   QUANTITATIVE 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.

As of December 31, 1999, 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 for 2000 are for average gas volumes of 231,250 Mcf per month beginning in February 2000 through September 2000 at (on average) a ceiling price of $2.80 and floor price of $2.56. The Company had no open oil hedging contracts at December 31, 1999.

Based on projected annual sales volumes for 2000 (excluding production forecast increases over 1999), a 10% decline in the prices the Company receives for its crude oil and natural gas production would have an approximate $4.2 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 8, 2000.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

<TABLE>
<CAPTION>

</TABLE>

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, 1999 and 1998, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 1999. 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, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1999, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

New Orleans, Louisiana,
February 16, 2000

CALLON PETROLEUM COMPANY
CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT SHARE DATA)

<TABLE>
<CAPTION>

	DECEMBER 31, 1999	DECEMBER 31, 1998
<S>	<C>	<C>
ASSETS		
Current assets:		
Cash and cash equivalents	$ 34,671	$ 6,300
Accounts receivable	5,362	6,024
Other current assets	1,004	1,924
Total current assets	41,037	14,248
Oil and gas properties, full-cost accounting method:		
Evaluated properties	511,689	444,579
Less accumulated depreciation, depletion and amortization	(361,758)	(345,353)
	149,931	99,226
Unevaluated properties excluded from amortization	44,434	42,679
Total oil and gas properties	194,365	141,905
Pipeline and other facilities, net	5,860	6,182
Other property and equipment, net	1,450	1,753
Deferred tax asset	14,995	16,348
Long-term gas balancing receivable	243	199
Other assets, net	1,927	1,017
Total assets	$ 259,877	$ 181,652
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 16,786	$ 11,257
Undistributed oil and gas revenues	2,082	1,720
Accrued net profits interest payable	1,676	129
Total current liabilities	20,544	13,106
Accounts payable and accrued liabilities to be refinanced	--	3,000
Long-term debt	100,250	78,250
Deferred revenue on sale of production payment	12,080	--
Accrued retirement benefits	2,107	2,323
Long-term gas balancing payable	516	489
Total liabilities	135,497	97,168

Stockholders' equity:		
Preferred Stock, $.01 par value; 2,500,000 shares authorized; 1,045,461 shares of Convertible Exchangeable Preferred Stock, Series A issued and outstanding at December 31, 1999 and 1,255,811 outstanding at December 31, 1998 with a liquidation preference of $26,136,525 at December 31, 1999	11	13
Common Stock, $.01 par value; 20,000,000 shares authorized; 12,239,238 and 8,178,406 shares outstanding at December 31, 1999 and 1998, respectively	122	82
Treasury stock (99,078 shares at cost)	(1,183)	(915)
Capital in excess of par value	149,425	109,429
Retained earnings (deficit)	(23,995)	(24,125)
Total stockholders' equity	124,380	84,484
Total liabilities and stockholders' equity	$ 259,877	$ 181,652

</TABLE>

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 1999, 1998 AND 1997
(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

<TABLE>
<CAPTION>

<S>	1999 <C>	1998 <C>	1997 <C>
Revenues:			
Oil and gas sales	$ 37,140	$ 35,624	$ 42,130
Interest and other	1,853	2,094	1,508
Total revenues	38,993	37,718	43,638
Costs and expenses:			
Lease operating expenses	7,536	7,817	8,123
Depreciation, depletion and amortization	16,727	19,284	16,488
General and administrative	4,575	5,285	4,433
Interest	6,175	1,925	1,957
Accelerated vesting and retirement benefits	--	5,761	--
Impairment of oil and gas properties	--	43,500	--
Total costs and expenses	35,013	83,572	31,001
Income (loss) from operations	3,980	(45,854)	12,637
Income tax expense (benefit)	1,353	(15,100)	4,200
Net income (loss)	2,627	(30,754)	8,437
Preferred stock dividends	2,497	2,779	2,795
Net income (loss) available to common shares	$ 130	$(33,533)	$ 5,642
Net income (loss) per common share:			
Basic	$ .01	$ (4.17)	$ .91
Diluted	$ .01	$ (4.17)	$ .88
Shares used in computing net income (loss) per common share:			
Basic	8,976	8,034	6,194
Diluted	9,075	8,034	6,422

</TABLE>

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(IN THOUSANDS)

<TABLE>
<CAPTION>

<S>	PREFERRED STOCK <C>	COMMON STOCK <C>	TREASURY STOCK <C>	UNEARNED COMPENSATION RESTRICTED STOCK <C>	CAPITAL IN EXCESS OF PAR VALUE <C>	RETAINED EARNINGS (DEFICIT) <C>
Balances, December 31, 1996	$ 13	$ 58	$ --	$ --	$ 74,027	$ 3,766
Net income (loss)	--	--	--	--	--	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)
Net income (loss)	--	--	--	--	--	2,627
Sale of common stock		37			40,994	--
Preferred stock dividends	--	--	--	--	--	(2,222)
Shares issued pursuant to employee benefit and option plan	--	--	--	--	274	--
Employee stock purchase plan	--	--	--	--	67	--
Restricted stock plan	--	(2)	--	--	(1,613)	--
Conversion of preferred shares to common	(2)	5	--	--	274	(275)
Stock buyback plan	--	--	(268)	--	--	--
Balances, December 31, 1999	$ 11	$122	$ (1,183)	$ --	$ 149,425	$ (23,995)

</TABLE>

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 1999, 1998 AND 1997
(IN THOUSANDS)

<TABLE>
<CAPTION>

	1999	1998	1997

<S>	<C>	<C>	<C>
Cash flows from operating activities:			
Net income (loss)	$ 2,627	$(30,754)	$ 8,437
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	17,232	19,791	16,924
Impairment of oil and gas properties	--	43,500	--
Amortization of deferred costs	707	619	467
Amortization of deferred production payment revenue	(2,710)	--	--
Deferred income tax expense (benefit)	1,353	(15,100)	4,200
Noncash compensation related to compensation plans	275	7,583	1,224
Changes in current assets and liabilities:			
Accounts receivable	662	6,144	493
Other current assets	920	(1,201)	(207)
Current liabilities	1,981	(876)	(3,809)
Change in gas balancing receivable	(44)	43	418
Change in gas balancing payable	27	85	14
Change in other long-term liabilities	(216)	--	249
Change in other assets, net	(1,617)	(129)	(1,073)
Cash provided (used) by operating activities	21,197	29,705	27,337
Cash flows from investing activities:			
Capital expenditures	(51,709)	(63,501)	(85,999)
Cash proceeds from sale of mineral interests	--	9,909	4,450
Cash provided (used) by investing activities	(51,709)	(53,592)	(81,549)
Cash flows from financing activities:			
Equity issued related to employee stock plans	68	414	90
Purchase of treasury shares	(268)	(915)	--
Payments on debt	(42,500)	--	(49,200)
Increase in debt	64,500	18,000	85,200
Restricted stock plan	(1,615)	(130)	(422)
Sale of common stock	41,031	--	29,267
Cash dividends on preferred stock	(2,333)	(2,779)	(2,795)
Cash provided (used) by financing activities	58,883	14,590	62,140
Net increase (decrease) in cash and cash equivalents	28,371	(9,297)	7,928
Cash and cash equivalents:			
Balance, beginning of period	6,300	15,597	7,669
Balance, end of period	$ 34,671	$ 6,300	$ 15,597

</TABLE>

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

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, 2000, with earlier application permitted. The Statement will create volatility in equity through other comprehensive income due to the mark-to-market of hedging contracts (see Note 6); however, the Company believes these instruments will be treated as hedges under FAS 133 and does not anticipate that FAS 133 will have a material impact on the Company's Statement of Operations.

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, 1999, estimated future abandonment costs on the Company's oil and gas properties, included as future development costs, were approximately $15.8 million.

Depreciation of other property and equipment is provided using the straight-line method over estimated lives of three to 20 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 was $38,000 at December 31, 1999 and 1998, respectively. Net recoveries were $2,000 in 1998 and net charge offs were $357,000 in 1997. There were no provisions to expense in the three-year period ended December 31, 1999.

For the year ended December 31, 1999, three companies purchased 12%, 16% and 29%, 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, EI 335, HI A494 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 production.

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, 1999. During the years ended December 31, 1999, 1998 and 1997, the Company made cash payments of $9,013,000, $6,229,000, and $4,167,000, respectively, for interest.

PER SHARE AMOUNTS

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 1999 and 1997 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 its antidilutive effect on diluted income or loss per common share.

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

	1999	1998	1997
(a) Net income (loss) available for common stock	$ 130	$(33,533)	$ 5,642
(b) Weighted average shares outstanding	8,976	8,034	6,194
(c) Dilutive impact of stock options	99	--	228
(d) Total diluted shares	9,075	8,034	6,422
Stock options excluded due to antidilutive impact	--	163	--
Basic earnings (loss) per share (a/b)	$ .01	$ (4.17)	$ .91
Diluted earnings (loss) per share (a/d)	$ .01	$ (4.17)	$ .88

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, 1999 and 1998. Fair value of long-term debt (specifically, the 10%, the 10.125% and the 10.25% 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, 1999 indicated a $457,000 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 were financed subsequent to year-end 1998 with long-term debt and therefore have been classified 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 required in 1999 and 1998. Accordingly, the Company has recorded a deferred tax asset at December 31, 1999 and 1998 as follows:

	DECEMBER 31, 1999	DECEMBER 31, 1998
	(IN THOUSANDS)	
Federal net operating loss carryforwards	$ 13,143	$ 7,916
Statutory depletion carryforward	4,087	4,083
Temporary differences:		
Oil and gas properties	(2,200)	3,979
Pipeline and other facilities	(2,051)	(2,164)
Non-oil and gas property	(102)	(101)
Other	2,118	2,635
Total tax asset	14,995	16,348
Valuation allowance	--	--

Net tax asset	$ 14,995	$ 16,348
	========	========

</TABLE>

At December 31, 1999, the Company had, for federal tax reporting purposes, net operating loss carryforwards ("NOL") of $37.6 million, which expire in 2000 through 2012. 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:

<TABLE>
<CAPTION>

	1999	1998	1997
	(IN THOUSANDS)		
<S>	<C>	<C>	<C>
Computed expense (benefit) at the expected statutory rate	$ 1,353	$(15,590)	$ 4,296
Other	--	490	(96)
Deferred income tax expense (benefit)	$ 1,353	$(15,100)	$ 4,200
	========	========	========

</TABLE>

4. DEFERRED REVENUE ON SALE OF PRODUCTION PAYMENT INTEREST

In June 1999, the Company acquired a working interest in the Mobile Block 864 Area where the Company already owned an interest. Concurrent with this acquisition, the seller received a volumetric production payment, valued at approximately $14.8 million, from production attributable to a portion of the Company's interest in the area over a 39-month period. The Company deferred the revenue associated with the sale of this production payment interest because a substantial obligation for future performance exists. Under the terms of the sale, the Company is obligated to deliver the production volumes free and clear of royalties, lease operating expenses, production taxes and all capital costs. The production payment was recorded at the present value of the volumetric production committed to the seller at market value and, beginning in June 1999, is amortized to oil and gas sales on the units-of-production method as associated hydrocarbons are delivered.

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

<TABLE>
<CAPTION>

	DECEMBER 31,	
	1999	1998
	(IN THOUSANDS)	
<S>	<C>	<C>
Credit Facility	$ 100	$ 18,100
10% Senior Subordinated Notes	24,150	24,150
10.125% Senior Subordinated Notes	36,000	36,000
10.25% Senior Subordinated Notes	40,000	--
	100,250	78,250
Less: current portion	--	--
	$100,250	$ 78,250
	========	========

</TABLE>

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 $30 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, the interest rate is equal to the lender's prime rate plus 0.50%. The Company, at its option, may fix the interest rate on all or a portion of the outstanding principal balance 2% above a defined "Eurodollar" rate for periods up to six months. The weighted average interest rate for the Credit Facility debt outstanding at December 31, 1999 and 1998 was 9.00% and 6.68%, respectively. Under the Credit Facility, a commitment fee of .50% per annum on 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. The Company expects various terms to be revised, including the extension of the maturity date, when the Credit Facility is renegotiated in 2000.

On November 27, 1996, the Company issued $24,150,000 of 10% Senior Subordinated Notes that will mature December 15, 2001. 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 September 15, 2002. 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.

On July 15, 1999, the Company completed its sale of $40 million of Senior Subordinated Notes due 2004 at 10.25%. The net proceeds of approximately $38.2 million were used to pay down the Credit Facility at that time. These notes are not entitled to any mandatory sinking fund payments and are subject to redemption at the Company's option at par plus unpaid interest at any time after March 15, 2001. The notes are listed on the New York Stock Exchange under the symbol "CPE 04" and are subject to a change

of control clause that obligates the Company to repurchase the 10.25% notes for 101% of par should a change of control occur. Interest is paid quarterly beginning September 15, 1999.

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, 1999.

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 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 contract are deferred and recognized in revenue when the oil and gas production is sold. In 1999, approximately $1,559,000 was recognized as a reduction of oil and gas revenue and $1,886,000 and $2,466,000 was recognized as additional oil and gas revenue in 1998 and 1997 as a result of such agreements.

As of December 31, 1999, 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 for 2000 are for average gas volumes of 231,250 Mcf per month beginning in February 2000 through September 2000 at (on average) a ceiling price of $2.80 and floor price of $2.56. The Company had no open oil hedging contracts at December 31, 1999.

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, 1999 total estimated site restoration; dismantlement and abandonment costs were approximately $5,690,000, 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.

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	1999	1998	1997
	(IN THOUSANDS)		
<S>	<C>	<C>	<C>
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$ 444,579	$ 398,046	$ 322,970
Property acquisition costs	24,153	9,464	51,751
Exploration costs	37,427	42,617	13,620
Development costs	5,530	4,361	14,155
Sale of mineral interests	--	(9,909)	(4,450)
End of period balance	$ 511,689	$ 444,579	$ 398,046
Unevaluated Properties (excluded from the full-cost pool) -			
Beginning of period balance	$ 42,679	$ 35,339	$ 26,235
Additions	4,890	11,156	16,924
Capitalized interest and general and administrative costs	7,120	8,955	5,163
Transfers to evaluated	(10,255)	(12,771)	(12,983)
End of period balance	$ 44,434	$ 42,679	$ 35,339
Accumulated depreciation, depletion and amortization			
Beginning of period balance	$ 345,353	$ 282,891	$ 266,716
Provision charged to expense	16,405	18,962	16,175
Impairment of oil and gas properties	--	43,500	--
End of period balance	$ 361,758	$ 345,353	$ 282,891

</TABLE>

Unevaluated property costs, primarily lease acquisition costs incurred at federal and state lease sales, unevaluated drilling costs and capitalized interest and general and administrative costs being excluded from the amortizable evaluated property base consisted of $13.1 million incurred in 1999, $12.1 million incurred in 1998 and $19.2 million incurred in 1997 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.

Depletion per unit-of-production (thousand cubic feet of gas equivalent) amounted to $.99, $1.19, and $1.02, for the years ended December 31, 1999, 1998, and 1997, respectively.

IMPAIRMENT OF OIL AND GAS PROPERTIES-1998

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 at December 31, 1998.

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, 1999 and 1998 the Trusts' assets (all cash and investments) totaled $5,690,000 and $6,360,000 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.

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 owners' 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, including Company discretionary contributions, 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 $466,000, $468,000, and $438,000 in the years 1999, 1998 and 1997, 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. These options have an expiration date 10 years from date of grant.

- - 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. All of such options are to be granted at an exercise price equal to the fair market value of the Common Stock on the date of grant. 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 Financial Accounting Standards Board No. 123 ("FAS 123"), "Accounting for Stock-Based Compensation", the Company's net income and earnings per common share would have been reduced to the following pro forma amounts:

<TABLE>
<CAPTION>

		1999	1998	1997
		-------	--------	------
		(IN THOUSANDS, EXCEPT PER SHARE DATA)		
<S>	<C>	<C>	<C>	<C>
Net income (loss):	As Reported	$ 130	$(33,533)	$5,642
	Pro Forma	(1,212)	(34,421)	4,977
Basic earnings (loss) per share:	As Reported	.01	(4.17)	.91

	Pro Forma	(.14)	(4.28)	.80
Diluted earnings (loss) per share:	As Reported	.01	(4.17)	.88
	Pro Forma	(.14)	(4.28)	.77

</TABLE>

Because the FAS 123 method of accounting does not apply 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, 1999, 1998 and 1997 and changes during the years then ended is presented in the table and narrative below:

<TABLE>
<CAPTION>

	1999		1998		1997	
	SHARES	WTD AVG EX PRICE	SHARES	WTD AVG EX PRICE	SHARES	WTD AVG EX PRICE
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Outstanding, beginning of year	1,266,000	$11.00	1,041,000	$11.19	1,030,000	$11.10
Granted	270,500	9.27	225,000	10.08	20,000	15.31
Exercised	--	--	--	--	(9,000)	10.00
Forfeited	--	--	--	--	--	--
Expired	--	--	--	--	--	--
Outstanding, end of year	1,536,500	$10.60	1,266,000	$11.00	1,041,000	$11.19
Exercisable, end of year	1,247,600	$10.47	802,250	$10.90	621,000	$10.65
Weighted average fair value of options granted	$ 4.94		$ 4.31		$ 6.30	

</TABLE>

At December 31, 1999, 1,496,500 of the 1,536,500 options outstanding have exercise prices between $9 and $13.50 with a weighted average exercise price of $10.50 and a weighted average remaining contractual life of 6.6 years. 1,207,600 of these option are exercisable at a weighted average exercise price of $10.34. The remaining 40,000 options have exercise prices between $13.50 and $15.31 with a weighted average exercise price of $14.53. All of these options are exercisable.

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 1999, 1998 and 1997.

<TABLE>
<CAPTION>

	1999	1998	1997
<S>	<C>	<C>	<C>
Risk free interest rate	6.3%	5.1%	6.8%
Expected life (years)	7.0	7.0	4.0
Expected volatility	46.0%	28.8%	41.1%
Expected dividends	--	--	--

</TABLE>

The Company awarded 225,000 performance shares under the 1996 Plan to the Company's Executive officers on August 23, 1996. All of the performance shares granted were scheduled to vest in whole on January 1, 2001. 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 and $714,000 in 1997 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 of Common Stock 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.

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. In 1999 certain other preferred stockholders, through private transactions, agreed to convert 210,350 shares of Preferred Stock into 502,637 shares of the Company's Common Stock under similar terms. Any noncash premium negotiated in excess of the conversion rate was recorded as additional preferred stock dividends and excluded from the Consolidated Statements of Cash Flows.

In November of 1999, the Company sold 3,680,000 shares of Common Stock in a public offering at a price to the public of $11.875 per share. Cash proceeds received by the Company were $41.1 million net of underwriting discount and offering costs.

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.

The 1999 estimates have been adjusted (per SEC guidelines) to exclude (i) volumes (approximately 5.8 billion cubic feet of natural gas) and (ii) future cash inflows of approximately $12.1 million associated with the volumetric production payment described in Note 4. The adjustments resulted in a reduction of approximately $7.0 million in standardized measure of discounted net cash flows associated with this volumetric production payment.

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, 1999	1998	1997
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	6,898	3,402	3,819
Revisions to previous estimates	(686)	(99)	(151)
Purchase of reserves in place	2,629	162	--
Sales of reserves in place	--	(1,531)	(78)
Extensions and discoveries	15,323	5,274	274
Production	(330)	(310)	(462)
End of period	23,834	6,898	3,402
Natural Gas (MMcf):			
Beginning of period	88,030	88,738	50,424
Revisions to previous estimates	(11,492)	(8,631)	(11,174)
Purchase of reserves in place	4,733	4,414	52,485
Sales of reserves in place	--	(684)	(164)
Extensions and discoveries	42,662	18,229	10,281
Production	(13,312)	(14,036)	(13,114)
End of period	110,621	88,030	88,738
Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	1,774	2,976	3,385
End of period	1,376	1,774	2,976
Natural Gas (MMcf):			
Beginning of period	76,895	88,010	49,491
End of period	76,295	76,895	88,010

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

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	1999	1998	1997
	(IN THOUSANDS)		
<S>	<C>	<C>	<C>
Future cash inflows	$ 847,930	$ 256,325	$ 285,953
Future costs -			
Production	(207,615)	(67,192)	(63,709)
Development and net abandonment	(123,749)	(36,581)	(12,984)
Future net inflows before income taxes	516,567	152,552	209,260
Future income taxes	(109,238)	(--)	(32,781)
Future net cash flows	407,329	152,552	176,479
10% discount factor	(151,007)	(52,801)	(48,400)
Standardized measure of discounted future net cash flows	$ 256,322	$ 99,751	$ 128,079

</TABLE>

CHANGES IN STANDARDIZED MEASURE

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	1999	1998	1997
	(IN THOUSANDS)		
<S>	<C>	<C>	<C>
Standardized measure - beginning of period	$ 99,751	$ 128,079	$ 130,169
Sales and transfers, net of production costs	(27,076)	(27,807)	(34,006)
Net change in sales and transfer prices, net of production costs	57,246	(33,029)	(66,880)
Exchange and sale of in place reserves	--	(4,445)	(2,428)
Purchases, extensions, discoveries, and improved recovery, net of future production and development costs	181,185	24,294	90,550
Revisions of quantity estimates	(22,438)	(9,409)	(13,751)
Accretion of discount	9,975	13,645	16,017
Net change in income taxes	(29,492)	7,926	21,633
Changes in production rates, timing and other	(12,829)	497	(13,225)
Standardized measure-end of period	$ 256,322	$ 99,751	$ 128,079

</TABLE>

13. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

<TABLE>
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	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(IN THOUSANDS, EXCEPT PER SHARE DATA)			
1999				
<S>	<C>	<C>	<C>	<C>
Total revenues	$ 8,374	$ 9,031	$ 10,584	$ 11,004
Total costs and expenses	7,659	8,690	8,986	9,678
Income taxes expense (benefit)	243	116	543	451
Net income (loss)	472	225	1,055	875
Net income (loss) per share-basic	(.04)	(.04)	.06	.03
Net income (loss) per share-diluted	(.04)	(.04)	.06	.03

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)

</TABLE>

During the fourth quarter of 1998, the Company recorded a non-cash 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 at December 31, 1998. See Note 8.

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

None.

PART III.

ITEMS 10, 11, 12 &13

For information concerning Item 10 - Directors and Executive Officers of the Registrant, 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 May 9, 2000 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 32 through 52.

Report of Independent Public Accountants

Consolidated Balance Sheets as of the Years Ended December 31, 1999 and 1998

Consolidated Statements of Operations for the Three Years in the Period Ended December 31, 1999

Consolidated Statements of Stockholders' Equity for the Three Years in the Period Ended December 31, 1999

Consolidated Statements of Cash Flows for the Three Years in the Period Ended December 31, 1999

Notes to Consolidated Financial Statements

(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:

<TABLE>
<S> <C>

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, filed August 4, 1994, Reg. No. 33-82408)

3.2 Certificate of Merger of Callon Consolidated Partners, L. P. with and into the Company dated September 16, 1994 (incorporated by reference from Exhibit 3.2 of the Company's Report on Form 10-K for the fiscal year ended December 31, 1994)

3.3 Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)

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

4.1 Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)
</TABLE>

<TABLE>
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4.2 Specimen Preferred Stock Certificate (incorporated by reference from Exhibit 4.2 of the Company's Registration Statement on Form S-1, filed November 13, 1995, Reg. No. 33-96700)

4.3 Designation for Convertible, Exchangeable Preferred Stock, Series A (incorporated by reference from Exhibit 4.3 of the Company's Registration Statement on Form S-1, filed November 13, 1995, 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, filed November 13, 1995, 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, filed November 22, 1996, Reg. No. 333-15501)

4.6 Form of Note Indenture for the Company's 10% Senior Subordinated Notes due 2001 (incorporated by reference from Exhibit 4.6 of the Company's Registration Statement on Form S-1, filed November 22, 1996, Reg. No. 333-15501)

4.7 Form of Note Indenture for the Company's 10.25% Senior Subordinated Notes due 2004 (incorporated by reference from Exhibit 4.10 of the Company's Registration Statement on Form S-2, filed June 25, 1999, Reg. No. 333-80579)

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)

9.2 Addendum to Stockholders' Agreement dated August 11, 1997 between Fred. Olsen Energy ASA, the Company and other stockholders of the Company (incorporated by reference from Exhibit 9.2 of the Company's Registration Statement on Form 8-A filed July 12, 1999)

9.3 Addendum to Stockholders' Agreement dated February 11, 1998 between Fred. Olsen Limited, the Company and other stockholders of the Company (incorporated by reference from Exhibit 9.3 of the Company's Registration Statement on Form 8-A filed July 12, 1999)

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)
</TABLE>

<TABLE>
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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, 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, 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, filed November 14, 1996, Reg. No. 333-15501)

10.10 Callon Petroleum Company 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)

10.11 Purchase and Sale Agreement between Callon Petroleum Operating Company and Murphy Exploration Company, dated May 26, 1999 (incorporated by reference from Exhibit 10.11 on Form S-2, filed June 14, 1999, Reg. No. 333-80579)

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*
</TABLE>

56

<TABLE>
<S> <C>

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, 1999 (EX-27) was filed electronically along with the Form 10-K.

99. Additional Exhibits*
</TABLE>

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

(b) Reports on Form 8-K.

The Company filed a Report on Form 8-K on November 4, 1999 under "Item 5 - Other Events."

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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

<TABLE>
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Date: March 23, 2000	/s/ FRED L.CALLON -- Fred L. Callon (principal executive officer, director)
Date: March 23, 2000	/s/ JOHN S. WEATHERLY -- John S. Weatherly (principal financial officer)
Date: March 23, 2000	/s/ JAMES O. BASSI -- James O. Bassi (principal accounting officer)

Date: March 23, 2000 /s/ JOHN S. CALLON

John S. Callon (director)

Date: March 23, 2000 /s/ DENNIS W. CHRISTIAN

Dennis W. Christian (director)

Date: March 23, 2000 /s/ B. F. WEATHERLY

B. F. Weatherly (director)

Date: March 23, 2000 /s/ JOHN C. WALLACE

John C. Wallace (director)
</TABLE>

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 23, 2000 By: /s/ JOHN S. WEATHERLY

John S. Weatherly, Senior Vice President and
Chief Financial Officer

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 16, 2000, 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

March 24, 2000
New Orleans, Louisiana

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THIS FINANCIAL DATA SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM THE CONSOLIDATED FINANCIAL STATEMENTS OF CALLON PETROLEUM COMPANY FOR THE PERIOD ENDING DECEMBER 31, 1999 WHICH ARE PRESENTED IN ITS ANNUAL REPORT ON FORM 10-K AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS.
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