CALLON PETROLEUM CO
Form 10-K405
April 01, 2002

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, 2001

COMMISSION FILE NUMBER 001-14039

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
Preferred Stock Purchase Rights	New York Stock Exchange
11% Senior Subordinated Notes due 2005	New York Stock Exchange
10.25% Senior Subordinated Notes due 2004	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 $98,778,082 as of March 18, 2002 (based on the last reported sale price of such stock on the New York Stock Exchange).

As of March 18, 2002, there were 13,424,216 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, 2001) relating to the Annual Meeting of Stockholders to be held on May 8, 2002, which is incorporated into Part III of this Form 10-K.

PART I.

ITEM 1. BUSINESS

OVERVIEW

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. Our properties are geographically concentrated primarily offshore in the Gulf of Mexico and onshore in Louisiana and Alabama. The public 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," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

In 1989, we began increasing our 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. We focused on reducing operating costs and implementing production enhancements through the application of technologically advanced production and recompletion techniques.

Over the past several years, we have also placed emphasis on the acquisition of acreage with exploration and development drilling opportunities in the Gulf of Mexico Shelf area. We acquired an infrastructure of production platforms, gathering systems and pipelines to minimize development expenditures of these drilling opportunities. We also joined with other industry partners, primarily Murphy Exploration and Production, Inc., ("Murphy") to explore federal offshore blocks acquired in the Gulf of Mexico. Over the last several years we have expanded our areas of exploration to include the Gulf of Mexico Deepwater area (generally 900 to 5,500 feet of water).

We ended the year 2001 with estimated net proved reserves of 303 billion cubic feet of natural gas equivalent ("Bcfe"). This represents a decrease of 9% from 2000 year-end estimated net proved reserves of 334 Bcfe.

The major focus of our future operations is expected to continue to be the exploration for and development of oil and gas properties, primarily in the Gulf of Mexico.

BUSINESS STRATEGY

Our goal is to increase shareholder value by increasing our reserves, production, cash flow and earnings. We seek to achieve these goals through the following strategies:

- Focus on Gulf of Mexico exploration with a balance between shelf and deepwater areas using the latest available technology.

- Aggressively explore our existing prospect inventory.

- Replenish our prospect inventory with increasing emphasis on prospect generation.

- Achieve moderate increases in current production levels through continued shelf exploration.

- Achieve significant increases in longer-term production levels through development of deepwater discoveries and ongoing deepwater exploration.

EXPLORATION AND DEVELOPMENT ACTIVITIES

Capital expenditures for exploration and development costs related to oil and gas properties totaled approximately $112.6 million in 2001. We incurred approximately $63.7 million in the Gulf of Mexico Shelf area.

The Gulf of Mexico Deepwater area expenditures ($31.9 million) accounted for the remainder of the total capital expended, along with $4.2 million incurred in leasehold and seismic acquisition costs and $12.8 million of interest and general and administrative costs allocable directly to exploration and development projects. The Gulf of Mexico Deepwater area expenditures included one unsuccessful exploration project totaling $2.2 million and the balance was incurred for additional delineation drilling and production facility fabrication at our Medusa discovery and the delineation drilling at Habanero.

As a result of recent successes in the Gulf of Mexico Deepwater area, we are faced with increased costs to develop these significant proved undeveloped reserves. A large portion of these future development costs will be incurred in 2002 and beyond. We are currently evaluating various financing alternatives to address these issues. While management believes there are a number of financing sources available to us, no assurances can be made that we will be able to fund these development costs.

RISK FACTORS

DECREASE IN OIL AND GAS PRICES MAY ADVERSELY AFFECT OUR RESULTS OF OPERATIONS AND FINANCIAL CONDITION. Our success is highly dependent on prices for oil and gas, which are extremely volatile. Any substantial or extended decline in the price of oil or gas would have a material adverse effect on us. Oil and gas markets are both seasonal and cyclical. The prices of oil and gas depend on factors we cannot control such as weather, economic conditions, levels of production, actions by OPEC and other countries and government actions. Prices of oil and gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;

- the amount of oil and gas that we are economically able to produce;

- our ability to attract capital to finance our operations and the cost of the capital;
- the amount we are allowed to borrow under our senior credit facility;
- the value of our oil and gas properties; and
- the profit or loss we incur in exploring for and developing our reserves.

UNLESS WE ARE ABLE TO REPLACE RESERVES, WHICH WE HAVE PRODUCED, OUR CASH FLOWS AND PRODUCTION WILL DECREASE OVER TIME. Our future success depends upon our ability to find, develop and acquire oil and gas reserves that are economically recoverable. As is generally the case for Gulf Coast properties, our producing properties usually have high initial production rates, followed by a steep decline in production. As a result, we must continually locate and develop or acquire new oil and gas reserves to replace those being depleted by production. We must do this even during periods of low oil and gas prices when it is difficult to raise the capital necessary to finance these activities and during periods of high operating costs when it is expensive to contract for drilling rigs and other equipment and personnel necessary to explore for oil and gas. Without successful exploration or acquisition activities, our reserves, production and revenues will decline rapidly. We cannot assure you that we will be able to find and develop or acquire additional reserves at an acceptable cost.

A SIGNIFICANT PART OF THE VALUE OF OUR PRODUCTION AND RESERVES IS CONCENTRATED IN A SMALL NUMBER OF OFFSHORE PROPERTIES, AND ANY PRODUCTION PROBLEMS OR INACCURACIES IN RESERVE ESTIMATES RELATED TO THOSE PROPERTIES WOULD ADVERSELY IMPACT OUR BUSINESS. During 2001, 44% of our daily production came from two of our properties in the Gulf of Mexico. Moreover, one property accounted for 25% of our production during this period. If mechanical problems, storms or other events curtailed a substantial portion of this production, our results of operations would be adversely affected. In addition, at December 31, 2001 most of our proved reserves were located in five fields in the Gulf of Mexico, with approximately 93% of our total net proved reserves attributable to these properties. If the actual reserves associated with any one of these five discoveries are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

OUR FOCUS ON EXPLORATION PROJECTS INCREASES THE RISKS INHERENT IN OUR OIL AND GAS ACTIVITIES. Our business strategy focuses on replacing reserves through exploration, where the risks are greater than in acquisitions and development drilling. Although we have been successful in exploration in the past, we cannot assure you that we will continue to increase reserves through exploration or at an acceptable cost. Additionally, we are often uncertain as to the future costs and timing of drilling, completing and producing wells. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or inequalities in formations;
- equipment failures or accidents;
- adverse weather conditions;

- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

BECAUSE WE DO NOT CONTROL ALL OF OUR PROPERTIES, ESPECIALLY OUR DEEPWATER PROPERTIES, WE HAVE LIMITED INFLUENCE OVER THEIR DEVELOPMENT. We do not operate all of our properties and have limited influence over the operations of some of these properties, particularly our deepwater projects. Our lack of control could result in the following:

- the operator may initiate exploration or development on a faster or slower pace than we prefer;
- the operator may propose to drill more wells or build more facilities on a project than we have funds for or that we deem appropriate, which may mean that we are unable to participate in the project or share in the revenues generated by the project even though we paid our share of exploration costs; and
- if an operator refuses to initiate a project, we may be unable to pursue the project.

Any of these events could materially reduce the value of our properties.

OUR DEEPWATER OPERATIONS HAVE SPECIAL OPERATIONAL RISKS THAT MAY NEGATIVELY AFFECT THE VALUE OF THOSE ASSETS. Drilling operations in the deepwater area are by their nature more difficult and costly than drilling operations in shallow water. They require 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 deepwater, the time required to commence production following a discovery is much longer than in shallow water and on-shore. Our deepwater discoveries and prospects will require the construction of expensive production facilities and pipelines prior to the beginning of production. We cannot estimate the costs and timing of the construction of these facilities with certainty, and the accuracy of our estimates will be affected by a number of factors beyond our control, including the following:

- decisions made by the operators of our deepwater wells;
- the availability of materials necessary to construct the facilities;
- the 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 our deepwater prospects and the discounted present value of reserves attributable to those prospects.

COMPETITIVE INDUSTRY CONDITIONS MAY NEGATIVELY AFFECT OUR ABILITY TO CONDUCT

OPERATIONS. We operate in the highly competitive areas of oil and gas exploration, development and production. We compete for the purchase of leases in the Gulf of Mexico from the U. S. government and from other oil and gas companies. These leases include exploration prospects as well as properties with proved reserves. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport oil and gas production;
- the standards we establish for the minimum projected return on an investment of our capital; and
- the availability of alternate fuel sources.

Our 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, technological and other resources than we do.

OUR COMPETITORS MAY USE SUPERIOR TECHNOLOGY, WHICH WE MAY BE UNABLE TO AFFORD OR WHICH WOULD REQUIRE COSTLY INVESTMENT BY US IN ORDER TO COMPETE. Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected. For example, marine seismic acquisition technology has been characterized by rapid technological advancements in recent years, and further significant technological developments could substantially impair our 3-D seismic data's value.

WE MAY NOT BE ABLE TO REPLACE OUR RESERVES OR GENERATE CASH FLOWS IF WE ARE UNABLE TO RAISE CAPITAL. We will be required to make substantial capital expenditures to develop our existing reserves, and to discover new oil and gas reserves.

Historically, we have financed these expenditures primarily with cash from operations, proceeds from bank borrowings and proceeds from the sale of debt and equity securities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources" for a discussion of our capital budget. We cannot assure you that we will be able to raise capital in the future. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially.

We expect to continue using our senior credit facility to borrow funds to supplement our available cash. The amount we may borrow under our senior credit facility may not exceed a borrowing base determined by the lenders based on their projections of our future production, future production costs, taxes, commodity prices and any other factors deemed relevant by our lenders. We cannot control the assumptions the lenders use to calculate our borrowing base. The lenders may, without our consent, adjust the borrowing base semiannually or in situations where we purchase or sell assets or issue debt securities. If our borrowings under the senior credit facility exceed the borrowing base, the lenders may require that we repay the excess. If this were to occur, we might have to sell assets or seek financing from other sources. Sales of assets could further reduce the amount of our borrowing base. We cannot assure you that we would be successful in selling assets or arranging substitute financing. If we were not able to repay borrowings under our senior credit facility to reduce the outstanding amount to less than the borrowing base, we would be in default under our senior credit facility. For a description of our senior credit facility and its principal terms and conditions, see "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Liquidity and Capital Resources."

OUR RESERVE INFORMATION REPRESENTS ESTIMATES THAT MAY TURN OUT TO BE INCORRECT IF THE ASSUMPTIONS UPON WHICH THESE ESTIMATES ARE BASED ARE INACCURATE. ANY MATERIAL INACCURACIES IN THESE RESERVE ESTIMATES OR UNDERLYING ASSUMPTIONS WILL MATERIALLY AFFECT THE QUANTITIES AND PRESENT VALUE OF OUR RESERVES. The process of estimating oil and gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus.

In order to prepare these estimates, we must project production rates and the timing of development expenditures. The assumptions regarding the timing and costs to commence production from our deepwater wells used in preparing our reserves are often subject to revisions over time as described under "our deepwater operations have special operational risks that may negatively affect the value of those assets." We must also analyze available geological, geophysical, production and engineering data, the extent, quality and reliability of which can vary. The process also requires economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and gas reserves are inherently imprecise. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net cash flows from our proved reserves referred to in this prospectus is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Information about reserves constitutes forward-looking information. See "Forward-Looking Statements" for information regarding forward-looking information. The discounted present value of our oil and gas reserves is prepared in accordance with guidelines established by the SEC. A purchaser of reserves would use numerous other factors to value our reserves. The discounted present value of reserves, therefore, does not represent the fair market value of those reserves.

On December 31, 2001, approximately 77.3% of the discounted present value of our estimated net proved reserves were proved undeveloped. Substantially all of these proved undeveloped reserves were attributable to our deepwater properties. Development of these properties is subject to additional risks as described above.

WEATHER, UNEXPECTED SUBSURFACE CONDITIONS, AND OTHER UNFORESEEN OPERATING HAZARDS MAY ADVERSELY IMPACT OUR ABILITY TO CONDUCT BUSINESS. There are many operating hazards in exploring for and producing oil and gas, including:

- our drilling operations may encounter unexpected formations or pressures, which could cause damage to equipment or personal injury;

- we may experience equipment failures which curtail or stop production; and

- we could experience blowouts or other damages to the productive formations that may require a well to be re-drilled or other corrective action to be taken.

In addition, any of the foregoing may result in environmental damages for which we will be liable. Moreover, a substantial portion of our operations are offshore and are subject to a variety of risks peculiar to the marine environment such as capsizings, collisions, hurricanes and other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. Offshore operations are also subject to more extensive governmental regulation.

We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

WE MAY NOT HAVE PRODUCTION TO OFFSET HEDGES; BY HEDGING, WE MAY NOT BENEFIT FROM PRICE INCREASES. Part of our business strategy is to reduce our exposure to the volatility of oil and gas prices by hedging a portion of our production. In a typical hedge transaction, we will have the right to receive from the other parties 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, we are required to pay the other parties this difference multiplied by the quantity hedged. We are required to pay the difference between the floating price and the fixed price when the floating price exceeds the fixed price regardless of whether we have 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 us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge. See "Quantitative and Qualitative Disclosures About Market Risks" for a discussion of our hedging practices.

COMPLIANCE WITH ENVIRONMENTAL AND OTHER GOVERNMENT REGULATIONS COULD BE COSTLY AND COULD NEGATIVELY IMPACT PRODUCTION. Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and discharge of materials into the environment or otherwise relating to environmental protection. For a discussion of the material regulations applicable to us, see "Federal Regulations," "State Regulations," and "Environmental Regulations." These laws and regulations may:

- require that we acquire permits before commencing drilling;
- restrict the substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; and
- require remedial measures to mitigate pollution from former operations, such as dismantling abandoned production facilities.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do 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, we may be subject to liability or we may be required to cease production from properties in the event of environmental damages.

FACTORS BEYOND OUR CONTROL AFFECT OUR ABILITY TO MARKET PRODUCTION AND OUR FINANCIAL RESULTS. The ability to market oil and gas from our wells depends upon numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and gas;
- the proximity of the gas production to gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and gas marketing; and
- federal regulation of gas sold or transported in interstate commerce.

Because of these factors, we may be unable to market all of the oil or gas we produce. In addition, we may be unable to obtain favorable prices for the oil and gas we produce.

IF OIL AND GAS PRICES DECREASE, WE MAY BE REQUIRED TO TAKE WRITEDOWNS. We may be required to writedown the carrying value of our oil and gas properties when oil and gas prices are low or if we have substantial downward adjustments to our estimated net proved reserves, increases in our estimates of development costs or deterioration in our exploration results. Under the full-cost method we use to account for our oil and gas properties, the net capitalized costs of our oil and gas properties may not exceed the present value, discounted at 10%, of future net cash flows from estimated net proved reserves, using period end oil and gas prices or prices as of the date of our auditor's report, plus the lower of cost or fair market value of our unproved properties. If net capitalized costs of our oil and gas properties exceed this limit, we must charge the amount of the excess to earnings. This type of charge will not affect our cash flows, but will reduce the book value of our stockholders' equity. We review the carrying value of our properties

quarterly, based on prices in effect as of the end of each quarter or at the time of reporting our results. Once incurred, a writedown of oil and gas properties is not reversible at a later date, even if prices increase.

FORWARD-LOOKING STATEMENTS

In this report, we have made many forward-looking statements. We cannot assure you that the plans, intentions or expectations upon which our forward-looking statements are based will occur. Our forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed elsewhere in this report. Forward-looking statements include statements regarding:

- our oil and gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- drilling of wells;
- the timing and amount of future production and operating costs;
- business strategies and plans of management; and
- prospect development and property acquisitions.

Some of the risks, which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include:

- general economic conditions;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;

- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;
- the uncertainty of our ability to attract capital;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business;
- actions of operators of our oil and gas properties; and
- weather conditions.

The information contained in this report, including the information set forth under the heading "Risk Factors," identifies additional factors that could affect our operating results and performance. We urge you to carefully consider these factors and the other cautionary statements in this report. Our forward-looking statements speak only as of the date made, and we have no obligation to update these forward-looking statements.

CORPORATE OFFICES

Our headquarters are located in Natchez, Mississippi, in approximately 51,500 square feet of owned space. In late 2000, we opened a field office in Houston, Texas, staffed with recently hired technical professionals, to enhance exploration and development efforts. We also maintain owned or leased field offices in the area of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available.

EMPLOYEES

We had 103 employees as of December 31, 2001, none of whom are currently represented by a union. We believe that we have good relations with our employees. We employ nine petroleum engineers and eight 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 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 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 may 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

We are engaged in the exploration, development, acquisition and production of oil and gas properties and natural gas transmission and provide oil and gas property management services for other investors. Our properties are concentrated offshore in the Gulf of Mexico and onshore, primarily, in Louisiana and Alabama. We have historically grown our reserves and production by focusing primarily on low to moderate risk exploration and acquisition opportunities in the Gulf of Mexico Shelf area. Over the last several years, we have expanded our area of exploration to include the Gulf of Mexico Deepwater area. As of December 31, 2001, our estimated net proved reserves totaled 30.2 million barrels of oil ("MBbl") and 121.5 billion cubic feet of natural gas ("Bcf"), 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 $272.1 million. Gas constitutes approximately 40% of our total estimated proved reserves and approximately 17% of our reserves are proved producing reserves.

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SIGNIFICANT PROPERTIES

The following table shows discounted cash flows and estimated net proved oil and gas reserves by major field, within focus area, for our nine largest fields and for all other properties combined at December 31, 2001.

		ESTIMATED NET PROVED RESERVES			
	OPERATOR	OIL (MBBLS)	GAS (MMCF) (b)	TOTAL (MMCFE) (b)	PR
GULF OF MEXICO SHELF:					
Mobile Block 864 Area	Callon	--	41,054	41,054	
Main Pass Block 26 SL 15827	Callon	40	915	1,152	
East Cameron Block 294	Unocal	14	2,860	2,945	
High Island Block A-494 "Snapper"	PetroQuest	--	4,614	4,614	
GULF OF MEXICO DEEPWATER:					
Garden Banks Blocks 738/782/826/827 "Entrada"	BP Amoco	7,823	29,341	76,279	
Mississippi Canyon 538/582 "Medusa"	Murphy	9,507	9,374	66,415	
Garden Banks Block 341 "Habanero"	Shell	4,736	12,270	40,685	

Ewing Bank Block 994 "Boomslang"	Murphy	7,244	13,040	56,505
ONSHORE AND OTHER:				
Big Escambia Creek	Exxon	412	1,027	3,500
Other	Various	433	6,958	9,557
TOTAL PROVED RESERVES		30,209	121,453	302,706

(a) Represents the present value of future net cash flows before deduction of federal income taxes, discounted at 10%, attributable to estimated net proved reserves as of December 31, 2001, as set forth in the Company's reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc. of Houston, Texas.

(b) The estimates include reserve volumes of approximately 1.2 Bcf with a pre-tax discounted present value of $2.9 million that are dedicated to a volumetric production payment.

GULF OF MEXICO DEEPWATER

Entrada, Garden Banks Blocks 738/782/826/827

The Entrada discovery is located in approximately 4,500 feet of water in the Gulf of Mexico. Two wells and seven sidetracks have been drilled to date on Garden Banks 782 on a northwest plunging salt ridge along the southern edge of the Entrada Basin. Multiple stacked amplitudes trapped against a salt or fault interface characterize the Entrada Area. We own a 20% working interest in this discovery with BP Amoco, the operator, holding the remaining working interest.

Information obtained in a data swap with another exploration company that has announced a similar discovery adjacent to Entrada, is being incorporated into the Entrada development plans. The owners of the adjacent discovery have announced their plans to construct production facilities to enable them to be a regional off-take point in Southeastern Garden banks. These plans include handling third party tie-ins, which we expect to include Entrada. First production from their discovery is expected in late 2004.

Medusa, Mississippi Canyon Block 538/582

Medusa was our third deepwater discovery and was announced in September 1999. We drilled the initial test well in 2,235 feet of water to a total depth of 16,241 feet and encountered over 120 feet of pay in two intervals. We performed subsequent sidetrack drilling from the well bore to determine the extent of the discovery. We drilled a second successful well in the first quarter of 2000 to further delineate the extent of the pay intervals. We own a 15% working interest, Murphy, the operator, owns a 60% interest and British-Borneo Petroleum, Inc. owns the remaining 25%.

In 2001 a delineation program began which included four development wells and one sidetrack. These will provide the take points for initial production. Also in 2001, the operator submitted an Authorization For Expenditure for a floating production system at Medusa and awarded the contract to J. Ray McDermott, Inc. Construction of the facility is in progress. Upon completion, it is estimated the production facility will have the capacity to handle 40,000 barrels of crude oil and 110 million cubic feet of natural gas per day. First production is anticipated in late 2002 or early 2003.

Habanero, Garden Banks Block 341

During February 1999 the initial test well on our 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 our second deepwater success. We own 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.

A field delineation program began in midyear 2001, which included sidetracking the existing well with three sidetracks. Development plans include sub-sea completion and tie back to an existing production facility in the area. The operator has submitted to the co-owners a development schedule with estimated initial production in November 2003.

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, we 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 our total working interest in the well to 55%.

A complete field study was initiated in 2001, which resulted in a delineation and development plan that is scheduled to commence by the second half of 2003. Plans include a sub-sea completion with a tieback to an existing shelf production facility. Plans could be altered if the Sidewinder prospect, located immediately to the southeast of Boomslang on Ewing Bank Block 995 and Green Canyon Blocks 24 and 25, is drilled and results in a discovery. This could result in the need for a stand-alone production facility to serve both Boomslang and Sidewinder. We own a 15% working interest in the Ewing Bank Block 995 and Green Canyon Blocks 24 and 25 leases.

GULF OF MEXICO SHELF

Mobile Block 864 Area

The Mobile Block 864 Area is located offshore Alabama in the federal waters of the Outer Continental Shelf area. We consummated five acquisitions in this area for a total of $63.8 million. In total, we 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. We have been appointed operator of the Mobile Block 864 unit and three other wells. Net average daily production during 2001 was 18 MMcf per day.

During the first quarter of 2001, we drilled the Mobile Block 908 #4, an exploratory well, and the Mobile Block 864 A-3, a development well, in our

Mobile Block 864 area, both of which were successful. During the fourth quarter of 2000, the Company performed acid stimulation on three wells. The 908 #4 well commenced production during February 2001 and the A-3 well commenced production during March 2001. These projects increased production in this area during 2001.

In the fourth quarter of 2001, we initiated a production acceleration program for Mobile Blocks 952, 953 and 955, which currently produce through the Mobile Block 864 unit facilities. Plans include at least one acceleration well, which was successfully drilled in the fourth quarter of 2001, stand-alone production facilities and the rerouting of production flow lines. The project is scheduled to be completed late in the first quarter or early second quarter 2002.

East Cameron Block 294

In the first quarter of 2001, this prospect was drilled at a water depth of 186 feet and encountered approximately 80 feet of pay in two intervals at approximately 3,500 and 4,200 feet. First production commenced in the first quarter of 2002 at a net average daily rate of 6 MMcf. We own a 50% working interest in this well and Unocal, the operator, owns the remaining interest.

Main Pass 26 / SL 15827 #1

We negotiated a farm-in agreement in 1998 for a 97% working interest after identifying a prospect on Main Pass Block 26 based upon a seismic survey we completed in 1996. In August 1998, we drilled the SL 15827 well to a depth of 10,450 feet. This well produced during 2001 at a net average daily rate of 2 MMcf of gas and 85 Bbls of oil. We operate this property.

Snapper, High Island Block A-494

In January 1999, we announced a discovery on our Snapper prospect, which was drilled to a total depth of 8,800 feet. In the second half of 2001, the well was sidetracked and a second well was drilled to test the same zone in an adjacent fault block. The second well had over 100 feet of pay which is fault separated from the initial well with no apparent water. We own a 50% working interest in these wells, which are operated by PetroQuest Energy. The wells began production in the third quarter of 2001, and averaged 7 net MMcf per day for December 2001.

ONSHORE

We own various small royalty and working interests in several onshore areas, which as of December 31, 2001 had total net proved reserves of 9.4 Bcfe with a discounted present value of $5.0 million. Over 50% of these reserves and their related discounted present value were attributable to our interest in the Big Escambia Creek gas field located in south Alabama and operated by Exxon/Mobil.

OIL AND GAS RESERVES

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

	YEARS ENDED DECEMBER 31,		
	2001(a)	2000(a)	1999(a)

		(IN THOUSANDS)	
Proved developed:			
Oil (Bbls)	885	2,192	1,376
Gas (Mcf)	52,375	67,463	82,109
Proved undeveloped:			
Oil (Bbls)	29,324	31,190	22,458
Gas (Mcf)	69,078	65,940	34,326
Total proved:			
Oil (Bbls)	30,209	33,382	23,834
Gas (Mcf)	121,453	133,403	116,435
Estimated pre-tax future net cash flows	$ 473,896	$1,610,320	$ 528,659
Pre-tax discounted present value	$ 272,053	$ 939,325	$ 296,513
Standardized measure of discounted future net cash flows	$ 254,857	$ 671,197	$ 256,322

(a) The estimates include reserve volumes of approximately 5.8 Bcf, $12.1 million of pre-tax future net cash flows and $10.7 million of pre-tax discounted present value in 1999, 3.5 Bcf, $31.8 million of pre-tax future net cash flows and $29.5 million of pre-tax discounted present value in 2000, and 1.2 Bcf, $2.9 million of pre-tax discounted present value in 2001, attributable to a volumetric production payment. Standardized measure of discounted future net cash flows does not include any volumes or cash flows associated with the volumetric production payment.

Our independent reserve engineers, Huddleston & Co., Inc. 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 Securities and Exchange 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 our control or the control of 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.

We have 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 we have drilled and completed during the periods indicated. All such wells were drilled in the continental United States including federal and state waters in the Gulf of Mexico.

	YEARS ENDED DECEMBER 31,					
	2001		2000		1999	
	GROSS	NET	GROSS	NET	GROSS	NET
Development:						
Oil	6	.45	2	.35	--	--
Gas	4	3.17	--	--	--	--
Non-productive	--	--	--	--	--	--
Total	10	3.62	2	.35	--	--
Exploration:						
Oil	--	--	1	.20	2	0.26
Gas	3	2.00	2	2.00	5	3.79
Non-productive	12	5.77	6	2.29	2	1.20
Total	15	7.77	9	4.49	9	5.25

We owned working and royalty interests in approximately 246 gross (6.7 net) producing oil and 288 gross (29.9 net) producing gas wells as of December 31, 2001. 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, some of our wells produce both oil and gas. At December 31, 2001, we had 3 gross (.53 net) wells with multiple completions. At December 31, 2001, we had 1 gross (.15 net) development oil well and 1 gross (1 net) exploratory gas well in progress.

LEASEHOLD ACREAGE

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2001.

	LEASEHOLD ACREAGE			
	DEVELOPED		UNDEVELOPED	
LOCATION	GROSS	NET	GROSS	NET

Alabama	19,451	16,635	80	2
Louisiana	8,178	5,221	3,795	1,212
Other States	860	388	934	744
Federal Waters	127,966	85,196	341,995	117,748
Total	156,455	107,440	346,804	119,706

As of December 31, 2001, we owned various royalty and overriding royalty interests in 1,336 net developed and 6,862 undeveloped acres. In addition, we owned 5,184 developed and 120,816 undeveloped mineral acres.

MAJOR CUSTOMERS

Our production is sold on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and gas production during each of the twelve-month periods ended:

	DECEMBER 31,		
	2001	2000	1999
Adams Resources Marketing, Ltd.	--	14%	16%
Columbia Energy Services	--	--	29%
Dynegy	8%	--	12%
Prior Energy Corporation	20%	--	--
Reliant Energy Services	49%	37%	--
Unocal Exploration Corporation	--	8%	--

Because alternative purchasers of oil and gas are readily available, we believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to market future oil and gas production.

TITLE TO PROPERTIES

We believe that the title to our 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 our opinion are not so material as to detract substantially from the use or value of such properties. Our 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 us or our 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 our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind owned by us.

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material affect on our 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 2001.

PART II.

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

Our common stock trades on the New York Stock Exchange under the symbol "CPE". The following table sets forth the high and low sale prices per share as reported for the periods indicated.

	QUARTER ENDED	HIGH	LOW
2000:			
	First quarter	$ 15.625	$ 9.625
	Second quarter	16.500	10.625
	Third quarter	17.625	12.500
	Fourth quarter	17.188	12.938
2001:			
	First quarter	$ 16.688	$10.000
	Second quarter	13.220	10.650
	Third quarter	11.820	5.900
	Fourth quarter	7.200	5.350

As of March 18, 2002, there were approximately 5,036 common stockholders of record.

We have not paid dividends on our common stock and intend to retain our cash flow from operations, net of preferred stock dividends, for the future operation and development of our business. In addition, our primary credit facility and the terms of our outstanding subordinated debt restrict payments of dividends on our common stock.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, as of the dates and for the periods indicated, selected financial information about us. The financial information for each of the five years in the period ended December 31, 2001 have been derived from our audited Consolidated Financial Statements 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 our future results.

CALLON PETROLEUM COMPANY
SELECTED HISTORICAL FINANCIAL INFORMATION
(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

	YEARS ENDED		
	2001	2000	19
STATEMENT OF OPERATIONS DATA:			
Revenues:			
Oil and gas sales	$ 60,010	$ 56,310	$ 3
Interest and other	1,742	1,767	
Total revenues	61,752	58,077	3
Costs and expenses:			
Lease operating expenses	11,252	9,339	
Depreciation, depletion and amortization	21,081	17,153	1
General and administrative	4,635	4,155	
Writedown of Enron derivatives	9,186	--	
Interest	12,805	8,420	
Accelerated vesting and retirement benefits	--	--	
Impairment of oil and gas properties	--	--	
Total costs and expenses	58,959	39,067	3
Income (loss) from operations	2,793	19,010	
Income tax expense (benefit)	977	6,463	
Net income (loss)	1,816	12,547	
Preferred stock dividends	1,277	2,403	
Net income (loss) available to common shares	$ 539	$ 10,144	$
Net income (loss) per common share:			
Basic	$ .04	$ .82	$
Diluted	$ .04	$ .80	$
Shares used in computing net income (loss) per common share:			
Basic	13,273	12,420	
Diluted	13,366	12,745	
BALANCE SHEET DATA (END OF PERIOD):			
Oil and gas properties, net	$ 343,158	$ 258,613	$ 19
Total assets	$ 372,095	$ 301,569	$ 25
Long-term debt, less current portion	$ 161,733	$ 134,000	$ 10
Stockholders' equity	$ 147,224	$ 136,328	$ 12

We use the full-cost method of accounting. Under this method of accounting, our net capitalized costs to acquire, explore and develop oil and gas properties may not exceed the standardized measure of our proved reserves. If these capitalized costs exceed a ceiling amount, the excess is charged to expense. As a result of the significant decline in oil and gas prices, we recorded a non-cash impairment expense related to our oil and gas properties in the amount of $43.5 million during the fourth quarter of 1998.

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 our financial condition and results of operations. Our 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, acquisition and production of oil and gas properties since 1950. Our revenues, profitability and future growth and the carrying value of our oil and gas properties are substantially dependent on prevailing prices of oil and gas and our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms is also influenced by oil and gas prices.

Our estimated net proved oil and gas reserves decreased at December 31, 2001 to 303 billion cubic feet of natural gas equivalent (Bcfe). This represents a decrease of 9% over previous year-end 2000 estimated proved reserves of 334 Bcfe. This decrease in 2001 is primarily due to production and revisions exceeding exploration additions to the reserve base. These reserve estimates include 1.2 Bcfe at December 31, 2001 and 3.5 Bcfe at December 31, 2000 dedicated to a volumetric production payment.

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 our control. 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 our carrying value of our proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. We use 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 our future production and do not use them for trading purposes. On a Mcfe basis, natural gas represents 92% of the budgeted 2002 production and 40% of proved reserves at year-end 2001.

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

RECENT ACCOUNTING PRONOUNCEMENTS. In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133 ("SFAS 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. SFAS 133 requires the Company to report changes in the fair value of our derivative financial instruments that qualify as cash flow hedges in other comprehensive income, a component of stockholders' equity, until realized. We adopted SFAS 133 effective January 1, 2001.

In July 2001, the Financial Accounting Standards Board approved Statement of Accounting Standards No. 143, Asset Retirement Obligations ("SFAS 143"). SFAS 143 will require that the fair value of abandonment

obligations be reflected as a liability, resulting in a corresponding increase to the historical cost of the related assets and potentially an adjustment for the cumulative effect of a change in accounting principle. This standard is required to be adopted by us beginning no later that January 1, 2003. We have not yet determined timing or the impact of the adoption of SFAS 143.

PROPERTY AND EQUIPMENT. We follow 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. We include in such amounts 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. Our 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. Such capitalized costs do not include any costs related to our production or our general corporate overhead. 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 our management determines these costs have been impaired and increase our depletion rates as they are transferred to evaluated property.

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. Increases in these costs increase our depletion rates. Additions to reserves decrease our depletion rates.

Under the full cost accounting rules of the SEC, we reviewed the carrying value of our proved oil and gas properties each quarter on a country-by-country basis. Under these rules, capitalized costs of proved oil and gas properties net of accumulated depreciation, depletion and amortization (DD&A) and deferred income taxes, may not exceed the present value of our estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects. These rules generally require pricing future oil and gas production at the unescalated market price for oil and gas at the end of each fiscal quarter and require a write-down if the "ceiling" is exceeded, unless prices recover sufficiently before the date of our auditor's report. Given the volatility of oil and gas prices, it is reasonably possible that our estimates of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas priced decline significantly, even if only for a short period of time, it is possible that writedowns of oil and gas properties could occur in the future. Based on prices at December 31, 2001 we would have been required to writedown our assets by $37.5 million. However, as of the date of our auditor's report, commodity prices increased sufficiently to eliminate any writedown.

Upon the acquisition or discovery of oil and gas properties, we estimate 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. These cost estimates, if revised upward for future changes, could increase our depletion rate.

The estimates used to calculate our oil and gas reserves are imprecise and are based on assumptions about future production levels, prices and future operating costs. As a result, the quantity of our proved reserves may be subject to downward or upward adjustment as additional information or analysis become available. In addition, estimates of the economically recoverable oil and gas reserves, classifications of such reserves,

and estimates of future net cash flows, prepared by different engineers or by the same engineers at different times, may vary substantially. In particular, the assumptions regarding the timing and costs to commence production from our deepwater wells used in preparing our reserves are subject to revisions over time. These assumptions could affect quantities used to calculate depletion and any significant revisions to our reserves could impact our depletion computations.

DERIVATIVES. We use derivative financial instruments for price protection purposes on a limited amount of our future production and do not use them for trading purposes. Such derivatives were accounted for in years prior to 2001 as hedges and have been recognized as an adjustment to oil and gas sales in the period in which they are related. Current accounting treatment is under SFAS 133.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of capital are cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Net cash and cash equivalents decreased during 2001 by $5.0 million. Cash provided from operating activities during 2001 totaled $35.2 million. Dividends paid on preferred stock were $1.3 million. Average debt outstanding was $164.9 million during 2001 compared to $118.3 million in 2000. At December 31, 2001, we had working capital of $.4 million, excluding current maturities of long-term debt and liabilities to be refinanced.

In May 2001, we initiated a combination of offerings of equity and senior notes to investors with proceeds to be used to call certain of our subordinated debt, repay borrowings under our senior secured credit facility and to finance capital expenditures. Subsequently, we withdrew our offer to sell the senior notes and the equity sale was terminated. Approximately $358,000 of costs associated with the withdrawn offering were expensed during the second quarter.

In early July of 2001, we closed a $95 million multiple advance term loan with a private lender. We drew $45 million on July 3, 2001 and paid down our revolving Credit Facility. We drew the remaining $50 million in December 2001. Under the terms of the agreement, we also issued warrants for the purchase, at a nominal exercise price, of 265,210 shares of our common stock to the lender and conveyed an overriding royalty interest equal to 2% of our net interest in four of our deepwater discoveries. The warrants and the overriding royalty interest were earned by the lender based on the ratio of the amount of the loan proceeds advanced to the total loan facility amount. This senior debt will mature March 31, 2005 and contains restrictions on certain types of future indebtedness and dividends on common stock.

Effective October 31, 2000, we entered into a $75 million Credit Facility with First Union National Bank. Borrowings under the Credit Facility are secured by mortgages covering substantially all of our producing oil and gas properties and guaranteed by our subsidiaries. The Credit Facility currently provides for a $50 million borrowing base ("Borrowing Base"), which is adjusted periodically on the basis of a discounted present value of future net cash flows attributable to our proved producing oil and gas reserves as determined by the bank. We may borrow, pay, reborrow and repay under the Credit Facility until July 31, 2002, on which date, we must repay in full all amounts then outstanding. The maturity date can be extended to July 31, 2004 if redemption of the 10.125% Senior Subordinated Notes due September 15, 2002 is completed prior to July 31, 2002. We expect to redeem or extend the Notes due in September 2002 prior to their maturity and anticipate extensions of maturity of the Credit Facility to July 2004. At December 31, 2001, availability under the Credit Facility was $50 million.

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. We are in compliance with these covenants at December 31, 2001.

Our plans for 2002 include non-discretionary capital expenditures of $50 million. Approximately $23 million of the investment will be allocated to the development of two of our deepwater discoveries. Our non-discretionary expenditure on the shelf includes the completion of a production acceleration project in the Mobile Block 864 area, well completions for 2001 discoveries and other commitments to existing properties.

Cash flow and current availability under the Credit Facility, subject to the maturity of the same as discussed above, is expected to be sufficient to fund our 2002 non-discretionary capital expenditures. These expenditures include completion of the Medusa deepwater discovery, currently scheduled to begin production late in the fourth quarter of 2002 or early 2003. We are currently evaluating options for redeeming the Senior Subordinated Notes due 2002. These options include, but are not limited to, (i) negotiated extensions of the maturity of a portion of these notes, (ii) increased availability under the Credit Facility and (iii) the issuance of additional Senior Notes.

We anticipate that these options would provide necessary capital to enable us to continue our operational activities until such time as production from the Medusa discovery begins. At that time, we anticipate the inclusion of the Medusa reserves and production will be integrated in our borrowing base from our Credit Facility and provide available borrowing capacity as well as cash flow from the new production for future discretionary capital expenditures.

Options currently under consideration to provide longer-term liquidity include (i) the sale of one of our deepwater discoveries, (ii) lease or similar financing of our deepwater infrastructure particularly at Medusa and (iii) the sale of common equity.

The following table describes our outstanding contractual obligations (in thousands) as of December 31, 2001:

CONTRACTUAL OBLIGATIONS	TOTAL	LESS THAN ONE YEAR	ONE-THREE YEARS	FOUR-FIVE YEARS	AF
Credit Facility	$ 100	$ 100	--	--	
Senior Notes	95,000	--	--	$ 95,000	
10.125% Senior Subordinated Debt	36,000	36,000	--	--	
10.25% Senior			--	--	
Subordinated Debt	40,000	--	$ 40,000	--	
11% Senior Subordinated Debt	33,000	--	--	33,000	
Capital lease (future minimum payments)	8,413	2,175	3,863	1,138	$

RESULTS OF OPERATIONS

The following table sets forth certain operating information with respect to our oil and gas operations for each of the three years in the period ended December 31, 2001.

	DECEMBER 31,		
	2001(a)(b)	2000(a)(b)	1999(a)(b)
Production:			
Oil (MBbls)	273	232	330
Gas (MMcf)	13,566	13,943	14,606
Total production (MMcfe)	15,206	15,334	16,589
Average daily production (MMcfe)	41.7	41.9	45.5
Average sales price:			
Oil (per Bbl)	$ 22.95	$ 27.88	$ 12.16
Gas (per Mcf)	$ 3.96	$ 3.57	$ 2.27
Total production (per Mcfe)	$ 3.95	$ 3.67	$ 2.24
Average costs (per Mcfe):			
Lease operating expenses	$ .73	$ .61	$ .46
Depletion	$ 1.37	$ 1.10	$ .99

General and administrative (net of management fees)	$ .30	$ .27	$ .28

(a) Includes hedging gains and losses.

(b) Includes volumes of 2,300 MMcf for each of the years 2001 and 2000 and volumes of 1,300 MMcf in 1999, 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, 2001 AND 2000

OIL AND GAS REVENUES

Oil and gas revenues for 2001 were $60.0 million, a 7% increase from the 2000 amount of $56.3 million. However, 2001 oil and gas production of 15,206 MMcfe decreased slightly from the 2000 amount of 15,334 MMcfe.

Oil production increased from 232,000 barrels in 2000 to 273,000 barrels in 2001 but the average sales price decreased from $27.88 in 2000 to $22.95 in 2001. As a result, oil revenues dropped from $6.5 million in 2000 to $6.3 million in 2001. The production increase was primarily from increased oil production at South Marsh Island 261 offset by older properties' normal and expected decline in production. The slight decrease in oil revenue was due to the decline in average oil prices received in 2001.

Gas revenues for 2001 were $53.7 million based on sales of 13.6 Bcf at an average sales price of $3.96 per Mcf. For 2000, gas revenues were $49.8 million based on production of 13.9 Bcf sold at an average sales price of $3.57 per Mcf. Our gas production in 2001 decreased when compared to last year as a result of production declines at East Cameron 275 and South Marsh Island 261, offset by increases in production at Mobile Block 864 and Chandeleur Block 40. The production declines at East Cameron 275 and South Marsh Island 261 were normal and expected as the 2000 rates were indicative of higher initial production. The Mobile Block 864 Area increased production due to a well stimulation program as well additions to production through exploratory and developmental drilling on the property. Gas revenue increased due to higher prices received for production in 2001.

LEASE OPERATING EXPENSES

Lease operating expenses increased from $9.3 million ($.61 per Mcfe) in 2000 to $11.3 million ($.73 per Mcfe) in 2001. The increase was attributable to higher operating costs at South Marsh Island 261 and at Mobile Block 864. Also, production declines related to older properties that have relatively fixed operating costs contributed to the higher per Mcf costs with lower production levels for those properties in 2001.

WRITEDOWN OF ENRON DERIVATIVES

In April of 2001, we entered into derivative contracts for 2002 production with Enron North America Corp. Enron North America Corp. filed for protection under the bankruptcy laws in late 2001. As a result of the credit risk associated with the derivatives with Enron North America Corp., hedge accounting was not available due to ineffectiveness as of September 30, 2001 and the contracts at December 31, 2001 have been marked to the market. In the fourth quarter of 2001, we charged to expense (non-cash) $9.2 million related to these Enron North America Corp. derivatives. We have no other contracts with Enron or their related subsidiaries.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation, depletion and amortization increased by 23% due to a combination of an increase in the amortization base due to higher drilling costs with reserve additions being less than expected from exploration efforts in 2001 and downward reserve revisions as a result of a field delineation program at Habanero.

Total charges increased from $17.2 million, or $1.12 per Mcfe in 2000 to $21.1 million, or $1.39 per Mcfe in 2001.

GENERAL AND ADMINISTRATIVE

General and administrative expenses for 2001 were $4.6 million, or $.30 per Mcfe, compared to $4.2 million, or $.27 per Mcfe, in 2000. This increase was due primarily to expenses incurred in the second quarter of 2001 related to our withdrawn debt offering.

INTEREST EXPENSE

Interest expense for 2001 was $12.8 million increasing from $8.4 million in 2000. This is a result of an increase in our long-term debt as well as higher interest rates associated with additional debt incurred in 2001.

INCOME TAXES

Our 2001 results include a deferred income tax expense of $977,000. We evaluated 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. We believe 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, 2000 AND 1999

OIL AND GAS REVENUES

Oil and gas revenues for 2000 were $56.3 million, a 52% increase from the 1999 amount of $37.1 million. However, 2000 oil and gas production of 15,334 MMcfe decreased by 8% from the 1999 amount of 16,589 MMcfe.

Oil production decreased from 330,000 barrels in 1999 to 232,000 barrels in 2000 but the average sales price increased from $12.16 in 1999 to $27.88 in 2000. As a result, oil revenues went from $4.0 million in 1999 to $6.5 million in 2000. The decrease in oil production was primarily from older properties' normal and expected decline in production and the depletion of Main Pass 31. The significant increase in oil revenue was due to the price of oil received for 2000 oil production more than doubling over 1999 average prices.

Gas revenues for 2000 were $49.8 million based on sales of 13.9 Bcf at an average sales price of $3.57 per Mcf. For 1999, gas revenues were $33.1 million based on production of 14.6 Bcf sold at an average sales price of $2.27 per Mcf.

When compared to 1999, production decreased due to a combination of older properties' normal and expected decline in production and the depletion of Main Pass 31. This decrease was offset by production gains at East Cameron Block 275 and South Marsh Island 261 as they began production in early 2000. East Cameron Block 275 experienced a significant drop in the fourth quarter of 2000 due to work on the host platform, which caused the well to be shut in for the entire quarter. This property was back online in January 2001 and currently is producing at or near levels prior to the shut-in. Gas revenue increased due to higher prices received for production in 2000, especially in the fourth quarter, compared to 1999 offset by the 5% decline in gas production.

LEASE OPERATING EXPENSES AND SEVERANCE TAXES

Lease operating expenses, including severance taxes, increased from $7.5 million ($.46 per Mcfe) in 1999 to $9.3 million ($.61 per Mcfe) in 2000. The increase per Mcfe is primarily attributable to production declines in 2000 related to older properties that have relatively fixed operating costs, which contributed to the higher per Mcf costs.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation, depletion and amortization increased by almost 3% due to an increase in the amortization base by 56%, primarily as a result of increased future development costs over 1999 offset by a 28% increase in reserves and by a decrease in production.

Total charges increased from $16.7 million, or $1.01 per Mcfe in 1999 to $17.2 million, or $1.12 per Mcfe in 2000.

GENERAL AND ADMINISTRATIVE

General and administrative expenses for 2000 were $4.2 million, or $.27 per Mcfe, compared to $4.6 million, or $.28 per Mcfe, in 1999. This 9% decrease is primarily due to an increase in direct overhead allocable to employees engaged in the acquisition, exploration and development of oil and gas properties in 2000.

INTEREST EXPENSE

Interest expense for 2000 and 1999 was $8.4 million and $6.2 million, respectively. This increase is a result of the increase in interest rates and in average debt outstanding in 2000 versus 1999. This average debt outstanding increase is directly related to the Senior Subordinated Notes issued in October 2000 and borrowings under the Credit Facility during the year.

INCOME TAXES

Our 2000 results include a deferred income tax expense of $6.5 million. We have evaluated the deferred income tax asset in light of our reserve quantity estimates, our long-term outlook for oil and gas prices and our expected level of future revenues and expenses. We believe it is more likely than not, based upon this evaluation, that we 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

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

We have put options in effect for 2002, other than those certain Enron North America Corp. derivatives discussed previously under Management Discussion and Analysis of Financial Condition and Results of Operation-Comparison of Results of Operations for the Years Ended December 31, 2001 and 2000 and in Note 6 of the financial statements. In March 2002, we purchased put options, which established an average floor price of $2.65 per Mcf on 6.1 Bcf of production from April 2002 through September 2002.

Based on projected annual sales volumes for 2002 (excluding forecast production increases over 2001), a 10% decline in the prices we receive for our crude oil and natural gas production would have an approximate $4.0 million impact on our revenues.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. 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 auditing standards generally accepted in the United States. 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, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 2 to the consolidated financial statements effective January 1, 2001, the Company adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities."

ARTHUR ANDERSEN LLP

New Orleans, Louisiana
March 29, 2002

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

	DECEMBER 31, 2001	DECEMBER 31, 2000
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,887	$ 11,876
Accounts receivable	5,908	9,244

Advance to operators	--	1,131
Other current assets	209	207
Total current assets	13,004	22,458
Oil and gas properties, full-cost accounting method:		
Evaluated properties	704,937	589,549
Less accumulated depreciation, depletion and amortization	(399,339)	(378,589)
	305,598	210,960
Unevaluated properties excluded from amortization	37,560	47,653
Total oil and gas properties	343,158	258,613
Pipeline and other facilities, net	5,364	5,537
Other property and equipment, net	2,455	1,790
Deferred tax asset	4,399	8,573
Long-term gas balancing receivable	473	643
Other assets, net	3,242	3,955
Total assets	$ 372,095	$ 301,569
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 9,985	$ 17,842
Undistributed oil and gas revenues	1,131	1,411
Accrued net profits interest payable	1,501	2,146
Accounts payable and accrued liabilities to be refinanced	9,558	--
Current maturities of long-term debt	37,345	--
Total current liabilities	59,520	21,399
Long-term debt-excluding current maturities	161,733	134,000
Deferred revenue on sale of production payment	2,406	7,236
Accrued retirement benefits	137	1,886
Long-term gas balancing payable	1,075	720
Total liabilities	224,871	165,241
Stockholders' equity:		
Preferred Stock, $.01 par value; 2,500,000 shares authorized; 600,861 shares of Convertible Exchangeable Preferred Stock, Series A issued and outstanding at December 31, 2001 with a liquidation preference of $15,021,525	6	6
Common Stock, $.01 par value; 20,000,000 shares authorized; 13,397,706 and 13,327,675 shares outstanding at December 31, 2001 and 2000, respectively	134	133
Treasury stock (99,078 shares at cost)	(1,183)	(1,183)
Capital in excess of par value	155,608	151,223
Accumulated other comprehensive income	5,971	--
Retained earnings (deficit)	(13,312)	(13,851)
Total stockholders' equity	147,224	136,328

Total liabilities and stockholders' equity	$ 372,095	$ 301,569

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

	2001	2000	1999
Revenues:			
Oil and gas sales	$ 60,010	$ 56,310	$ 37,140
Interest and other	1,742	1,767	1,853
Total revenues	61,752	58,077	38,993
Costs and expenses:			
Lease operating expenses	11,252	9,339	7,536
Depreciation, depletion and amortization	21,081	17,153	16,727
General and administrative	4,635	4,155	4,575
Writedown of Enron derivatives	9,186	--	--
Interest	12,805	8,420	6,175
Total costs and expenses	58,959	39,067	35,013
Income from operations	2,793	19,010	3,980
Income tax expense	977	6,463	1,353
Net income	1,816	12,547	2,627
Preferred stock dividends	1,277	2,403	2,497
Net income available to common shares	$ 539	$ 10,144	$ 130
Net income per common share:			
Basic	$ .04	$ .82	$ .01
Diluted	$ .04	$ .80	$ .01

Shares used in computing net income per common share:			
Basic	13,273	12,420	8,976
Diluted	13,366	12,745	9,075

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

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

	PREFERRED STOCK	COMMON STOCK	TREASURY STOCK	CAPITAL IN EXCESS OF PAR VALUE	ACCUMULATE OTHER COMPREHENSI INCOME
Balances, December 31, 1998	$ 13	$ 82	$ (915)	$ 109,429	$ --
Net income	--	--	--	--	--
Sale of common stock	--	37	--	40,994	--
Preferred stock dividends	--	--	--	--	--
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 stock	(2)	5	--	274	--
Stock buyback plan	--	--	(268)	--	--
Balances, December 31, 1999	11	122	(1,183)	149,425	--
Net income	--	--	--	--	--
Preferred stock dividends	--	--	--	--	--
Shares issued pursuant to employee benefit and option plan	--	--	--	1,069	--
Employee stock purchase plan	--	--	--	269	--
Tax benefits related to stock compensation plans	--	--	--	41	--
Conversion of preferred shares to common	(5)	11	--	419	--
Balances, December 31, 2000	6	133	(1,183)	151,223	--
Comprehensive income:					
Net income	--	--	--	--	--
Other comprehensive income	--	--	--	--	5,971
Total comprehensive income					

Preferred stock dividends	--	--	--	--	--
Shares issued pursuant to employee benefit and option plan	--	1	--	942	--
Employee stock purchase plan	--	--	--	357	--
Tax benefits related to stock compensation plans	--	--	--	18	--
Warrants	--	--	--	3,068	--
Balances, December 31, 2001	$ 6	$ 134	$ (1,183)	$ 155,608	$ 5,971

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2001, 2000 AND 1999
(IN THOUSANDS)

	2001
Cash flows from operating activities:	
Net income	$ 1,816
Adjustments to reconcile net income (loss) to cash provided by operating activities:	
Depreciation, depletion and amortization	21,709
Amortization of deferred costs	2,485
Amortization of deferred production payment revenue	(4,830)
Writedown of Enron derivatives	9,186
Deferred income tax expense	977
Noncash charge related to compensation plans	942
Changes in current assets and liabilities:	
Accounts receivable	3,336
Advance to operators	1,131
Other current assets	(2)
Current liabilities	(8,782)
Increase in accounts payable and accrued liabilities to be refinanced	9,558
Change in gas balancing receivable	170
Change in gas balancing payable	355
Change in other long-term liabilities	(1,749)
Change in other assets, net	(1,071)
Cash provided (used) by operating activities	35,231
Cash flows from investing activities:	
Capital expenditures	(113,833)
Cash proceeds from sale of mineral interests	1,195
Cash provided (used) by investing activities	(112,638)
Cash flows from financing activities:	

Equity issued related to employee stock plans	357
Purchase of treasury shares	--
Payment on debt	(84,900)
Increase in debt	155,000
Deferred financing costs	(2,374)
Restricted stock plan	--
Sale of common stock	--
Capital lease	5,612
Cash dividends on preferred stock	(1,277)
Cash provided (used) by financing activities	72,418
Net increase (decrease) in cash and cash equivalents	(4,989)
Cash and cash equivalents:	
Balance, beginning of period	11,876
Balance, end of period	$ 6,887

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

CALLON PETROLEUM COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

GENERAL

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.

LIQUIDITY AND CAPITAL RESOURCES

As discussed in Note 5, the $36.0 million of the 10.125% Senior Subordinated Notes will mature on September 15, 2002. When these notes are extended or redeemed, maturity of the Credit Facility, currently scheduled for July 31, 2002, can be extended until July 31, 2004. We are currently evaluating options for redeeming the Senior Subordinated Notes due 2002. These options include, but are not limited to, (i) negotiated extensions of the maturity of a portion of these notes, (ii) increased availability under the Credit Facility and (iii) the issuance of additional Senior Notes.

Capital commitments in 2002 include non-discretionary capital expenditures and the redemption or extension of the $36.0 million of the 10.125% Senior Subordinated Notes that will mature on September 15, 2002. Capital expenditures include completion of the Medusa deepwater discovery, currently scheduled to begin production late in the fourth quarter of 2002. The Company expects that, in addition to cash flow generated during 2002 and current availability under the Credit Facility, approximately $27 million of additional funding will be required to finance our capital commitments. We expect these requirements to be met through the options discussed above. As of March 27, 2002, the company has obtained a commitment from holders of approximately $10 million of the Notes to extend the maturity of the Notes until 2004.

We anticipate that these funding sources will provide necessary capital to enable us to continue our operational activities until such time as production from the Medusa discovery begins. At that time, we anticipate the inclusion of the Medusa reserves and production will be integrated in our borrowing base from our Credit Facility and provide available borrowing capacity as well as significant additional cash flow from the new production for future discretionary capital expenditures.

Longer-term liquidity options currently under consideration include (i) the sale of one of our deepwater discoveries, (ii) lease or similar financing of our deepwater infrastructure, particularly at Medusa and (iii) the sale of common equity.

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 ("SFAS 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. The Company adopted SFAS 133 effective January 1, 2001.
SFAS 133 requires the Company to report changes in the fair value of our derivative financial instruments that qualify as cash flow hedges in other comprehensive income, a component of stockholders' equity, until realized. See Note 6 for a discussion of our derivative financial instruments.

As discussed in Note 1, the Company adopted SFAS 133 effective January 1, 2001. The cumulative effect of the accounting change, net of tax, recorded as other comprehensive loss was $3.8 million. In 2001, this amount was offset by an increase in the fair value of derivatives recorded as other comprehensive income and the settlement of the derivatives that contractually matured in 2001.

In July 2001, the Financial Accounting Standards Board approved Statement of Accounting Standards No. 143, Asset Retirement Obligations ("SFAS 143"). SFAS 143 will require that the fair value of abandonment obligations be reflected as a liability, resulting in a corresponding increase to the historical cost of the related assets and potentially an adjustment for the cumulative effect of a change in accounting principle. This standard is required to be adopted by the Company beginning no later that January 1, 2003. The Company has not yet determined timing or the impact of the adoption of SFAS 143.

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. Such capitalized costs do not include any costs related to production or general corporate overhead. 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.

Depreciation of other property and equipment is provided using the straight-line method over estimated lives of three to 20 years. Depreciation of pipeline and other facilities is provided using the straight-line method over estimated lives of 15 to 27 years.

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 recorded a liability 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 and will expire in July 2002.

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. Imbalance positions are not significant at December 31, 2001.

DERIVATIVES

The Company uses derivative financial instruments for price protection purposes on a limited amount of its future production and does not use them for trading purposes. Such derivatives were accounted for, prior to adoption of SFAS 133, as hedges and have been recognized as an adjustment to oil and gas sales in the period in which they are related. Current accounting treatment is under SFAS 133 (see Note 6).

ACCOUNTS RECEIVABLE

Accounts receivable consists primarily of accrued oil and gas production receivables. The balance in the reserve for doubtful accounts included in accounts receivable was $68,000 and $78,000 at December 31, 2001 and 2000, respectively. Net charge offs were $10,000 in 2001 and net recoveries were $40,000 in 2000. There were no provisions to expense in the three-year period ended December 31, 2001.

MAJOR CUSTOMERS

Our production is sold primarily on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and gas production during each of the twelve-month periods ended:

	DECEMBER 31, 2001	2000	1999
Adams Resources Marketing, Ltd.	--	14%	16%
Columbia Energy Services	--	--	29%
Dynegy	8%	--	12%
Prior Energy Corporation	20%	--	--
Reliant Energy Services	49%	37%	--
Unocal Exploration Corporation	--	8%	--

Because alternative purchasers of oil and gas are readily available, we believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to market future oil and gas 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.

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The Company paid no federal income taxes for the three years ended December 31, 2001. During the years ended December 31, 2001, 2000 and 1999, the Company made cash payments of $16,441,000, $11,449,000 and $9,013,000 respectively, for interest.

PER SHARE AMOUNTS

Basic income 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 income or loss per common share was 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. 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 reconciliation of the basic and diluted per share computation is as follows (in thousands, except per share amounts):

	2001	2000	1999
(a) Net income available for common stock	$ 539	$ 10,144	$ 130
Preferred dividends assuming conversion of preferred stock (if dilutive)	--	--	--
(b) Income available for common stock assuming conversion of preferred stock (if dilutive)	$ 539	$ 10,144	$ 130
(c) Weighted average shares outstanding	13,273	12,420	8,976
Dilutive impact of stock options	27	325	99
Dilutive impact of warrants	66	--	--

Convertible preferred stock (if dilutive)	--	--	--
(d) Total diluted shares	13,366	12,745	9,075
Stock options and warrants excluded due to antidilutive impact	1,438	150	590
Basic income per share (a/c)	$ .04	$ .82	$ .01
Diluted income per share (b/d)	$ .04	$ .80	$ .01

FAIR VALUE OF FINANCIAL INSTRUMENTS

Fair value of cash, cash equivalents, accounts receivable, accounts payable, the capital lease and the Credit Facility approximates book value at December 31, 2001 and 2000. Fair value of long-term debt (specifically, the 10.125%, the 10.25%, the 11% Senior Subordinated Notes and the 12% Senior Notes) have an estimated fair value of between 95% and 97% of face value at December 31, 2001.

3. INCOME TAXES

The Company follows the asset and liability method of accounting for deferred income taxes prescribed by Statement of Financial Accounting Standards No. 109 ("SFAS 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 2001 or 2000. Accordingly, the Company has recorded a deferred tax asset at December 31, 2001 and 2000 as follows:

	DECEMBER 31,	
	2001	2000
	(IN THOUSANDS)	
Federal net operating loss carryforwards	$ 29,723	$ 14,352
Statutory depletion carryforward	4,184	4,152
Temporary differences:		
Oil and gas properties	(28,685)	(8,937)
Pipeline and other facilities	(1,822)	(1,938)
Non-oil and gas property	(62)	(81)
Other	1,061	1,025
Total tax asset	4,399	8,573
Valuation allowance	--	--
Net tax asset	$ 4,399	$ 8,573

At December 31, 2001, the Company had, for federal tax reporting purposes, net operating loss carryforwards of $84.9 million, which expire in 2002 through

2016. Net operating loss carryforwards includes approximately $1.5 million of the total that will expire within the next five years. Additionally, the Company had available for tax reporting purposes $11.9 million in statutory depletion deductions, which can be carried forward for an indefinite period.

The Company has significant state net operating loss carryforwards that are not included in the deferred tax asset above, as the Company does not anticipate generating taxable state income in the states in which these loss carryforwards apply. The Company has very limited state taxable income as primarily all of its revenue is generated in federal waters not subject to state income taxes.

The provision for income taxes at the Company's effective tax rate approximated the provision for income taxes at the statutory rate.

4. OTHER COMPREHENSIVE INCOME

The Company did not have any items of other comprehensive income prior to 2001. A recap of the Company's 2001 comprehensive income (net of tax) is shown below (in thousands):

	YEAR ENDED DECEMBER 31, 2001
Other comprehensive income (loss):	
Cumulative effect of change in accounting principle	$(3,764)
Change in unrealized derivatives' fair value	9,735
Total other comprehensive income	$ 5,971

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

	DECEMBER 31, 2001	2000
	(IN THOUSANDS)	
Credit Facility	$ 100	$ 25,000
Senior Notes, net of discount	84,366	--
10.125% Senior Subordinated Notes (due 2002)	36,000	36,000
10.25% Senior Subordinated Notes (due 2004)	40,000	40,000

11% Senior Subordinated Notes (due 2005)	33,000	33,000
Capital lease	5,612	--
	199,078	134,000
Less: current portion	37,345	--
	$ 161,733	$ 134,000

The Company negotiated a new Credit Facility effective October 31, 2000 with First Union National Bank. Borrowings under the Credit Facility are secured by mortgages covering substantially all of the Company's producing oil and gas properties. Currently, the Credit Facility is for $75 million with an initial $50 million borrowing base ("Borrowing Base"), which is adjusted periodically on the basis of a discounted present value of future net cash flows attributable to the Company's proved producing oil and gas reserves. Pursuant to the Credit Facility, the interest rate is equal to the lender's prime rate plus 0.25%. The Company, at its option, may fix the interest rate on all or a portion of the outstanding principal balance at 1.5% to 2.0% above a defined "Eurodollar" rate for periods up to six months depending on borrowing base utilization. The weighted average interest rate for the Credit Facility debt outstanding at December 31, 2001 and 2000 was 4.75% and 8.53%, respectively. Under the Credit Facility, a commitment fee of 0.25% or 0.375% per annum, depending on the amount of the unused portion of the borrowing base, is payable quarterly. The Company may borrow, pay, reborrow and repay under the Credit Facility until July 31, 2002 up to the borrowing base amount, on which date, the Company must repay in full all amounts then outstanding. The maturity date will extend to July 31, 2004 upon redemption of the 10.125% Senior Subordinated Notes due September 15, 2002.

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. The 10.125% Senior Subordinated Notes due September 15, 2002 have been classified as a current liability.

On July 15, 1999, the Company completed the 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 notes for 101% of par should a change of control occur. Interest is paid quarterly.

The Company completed the sale of $33 million of 11% Senior Subordinated Notes due 2005, on October 26, 2000. The Company netted $31.5 million from the offering after deducting the underwriters' discount and offering expenses. Approximately $20.8 million of the net proceeds from the offering were used to purchase a portion of the Company's outstanding 10% Senior Subordinated Notes due 2001 in conjunction with a tender offer. The Company redeemed the remaining $3.4 million of its 10% Senior Subordinated Notes due 2001 not tendered in the offer.

In May 2001, the Company initiated a combination of offerings of equity and senior notes to investors with proceeds to be used to call certain of the Company's subordinated debt, repay borrowings under its senior secured credit facility and to finance capital expenditures. Subsequently, the Company withdrew its offer to sell the senior notes and the equity sale was terminated. Approximately $358,000 of costs associated with the withdrawn offering were expensed during the quarter.

In July 2001, the Company entered into a $95 million multiple advance term loan with a private lender. The Company issued $45 million of 12% Senior Notes upon closing of the loan and issued the remaining $50 million of Senior Notes in December 2001. Under the terms of the agreement Callon also issued warrants to purchase, at a nominal exercise price, 265,210 shares of its common stock (fair value of $3.1 million) and conveyed an overriding royalty interest equal to 2% of the Company's net interest in four existing deepwater discoveries (fair value of $5.9 million). The warrants and the overriding royalty interest were earned by the lender based on the ratio of the amount of the loan proceeds advanced to the total loan facility amount. The Senior Notes will mature March 31, 2005, have an effective interest rate of approximately 16% and contain restrictions on certain types of future indebtedness.

In December 2001, the Company entered into a ten-year gas processing agreement associated with a production facility on Callon's Mobile 952 field with Hanover Compression Limited Partnership, which is being accounted for as a capital lease. Total minimum obligations are $8.4 million with interest representing approximately $2.8 million and the present value minimum obligation were $5.6 million ($1.2 million current).

Future minimum lease payments and debt maturities (in thousands) are as follows:

YEAR	CAPITAL LEASE PAYMENTS	DEBT
2002	$ 2,175	$ 36,100
2003	1,982	--
2004	1,881	40,000
2005	752	128,000
2006	413	--
Thereafter	1,236	--

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The Credit Facility, the subordinated debt and the $95 million Senior Notes 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, 2001.

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. Approximately $3,290,000 and $1,559,000 were recognized as a reduction of oil and gas revenue in 2000 and 1999 respectively, and $1,371,000 was recognized as additional oil and gas revenue in 2001 as a result of such agreements.

In March 2002, the Company purchased put options, which established an average floor price of $2.65 per Mcf on 6.1 Bcf of production from April 2002 through September 2002.

In April of 2001, the Company entered into derivative contracts for 2002 production with Enron North America Corp. These agreements are for average gas volumes of approximately 600,000 Mcf per month in 2002 with a weighted average ceiling price of $6.09 and floor price of $4.11. Enron North America Corp. filed for protection under the bankruptcy laws in late 2001. As a result of the credit risk associated with the derivatives with Enron North America Corp., hedge accounting was not available due to ineffectiveness as of September 30, 2001 and the contracts at December 31, 2001 have been marked to the market. In the fourth quarter of 2001, the Company charged to expense (non-cash) $9.2 million related to these Enron North America Corp. derivatives. The Company has no other contracts with Enron or its subsidiaries.

The $5,971,000 (net of tax) recorded in other comprehensive income at December 31, 2001 is related to the fair value as of September 30, 2001 of the natural gas collar contracts with Enron North America Corp., which matures in 2002. As the contracts mature in 2002, the Company will record non-cash revenue each month, offsetting the amounts in other comprehensive income related to the derivatives.

The Company has no other derivative contracts.

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, 2001 total estimated site restoration, dismantlement and abandonment costs were approximately $6,567,000, 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.

From time to time, the Company, as part of the Consolidation and other capital transactions, entered into Registration Rights Agreements whereby certain parties to the transactions 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 firm commitment public offerings 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 broker's discounts and commissions, which will be paid by the respective sellers of the Common Stock.

The Company is involved in various claims and lawsuits incidental to its business. In the opinion of management, the ultimate liability thereunder, if any, will not have a material adverse effect on the financial position or results of operations of the Company.

The Company's activities are subject to 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 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 polices thereunder, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

8. OIL AND GAS PROPERTIES

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

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
		(IN THOUSANDS)	
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$ 589,549	$ 511,689	$ 444,579
Property acquisition costs	1,713	3,211	24,153
Exploration costs	85,782	51,837	37,427
Development costs	34,980	25,242	5,530
Sale of mineral interests	(7,087)	(2,430)	--
End of period balance	$ 704,937	$ 589,549	$ 511,689
Unevaluated Properties (excluded from amortization) -			
Beginning of period balance	$ 47,653	$ 44,434	$ 42,679
Additions	2,350	4,381	4,890
Capitalized interest	4,879	4,548	3,497
General and administrative costs	6,410	5,036	3,623
Transfers to evaluated	(23,732)	(10,746)	(10,255)
End of period balance	$ 37,560	$ 47,653	$ 44,434

Accumulated depreciation, depletion and amortization			
Beginning of period balance	$ 378,589	$ 361,758	$ 345,353
Provision charged to expense	20,750	16,831	16,405
End of period balance	$ 399,339	$ 378,589	$ 361,758

Unevaluated property costs, primarily lease acquisition costs incurred at federal lease sales, unevaluated drilling costs, capitalized interest and general and administrative costs being excluded from the amortizable evaluated property base consisted of $7.5 million incurred in 2001, $8.3 million incurred in 2000 and $21.9 million incurred in 1999 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 Company expects that the majority of these costs will be evaluated over the next three to five year period.

Depletion per unit-of-production (thousand cubic feet of gas equivalent) amounted to $1.37, $1.10 and $.99 for the years ended December 31, 2001, 2000, and 1999, respectively.

Under the full cost accounting rules of the SEC, the Company reviews the carrying value of its proved oil and gas properties each quarter on a country-by-country basis. Under these rules, capitalized costs of proved oil and gas properties net of accumulated depreciation, depletion and amortization (DD&A) and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects. These rules generally require pricing future oil and gas

production at the unescalated market price for oil and gas at the end of each fiscal quarter and require a write-down if the "ceiling" is exceeded, unless prices recover sufficiently before the date of the auditor's report. Given the volatility of oil and gas prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas priced decline significantly, even if only for a short period of time, it is possible that writedowns of oil and gas properties could occur in the future. Based on prices at December 31, 2001 the Company would be required to writedown its assets by $37.5 million. However, as of the date of the auditor's report, commodity prices increased sufficiently to eliminate any writedown.

9. NET PROFITS INTEREST

From 1989 through 1994, the Constituent Entities 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, 2001 and 2000, the Trusts' assets (all cash and investments) totaled $6,567,000 and $6,227,000 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:

o 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 $595,000, $500,000 and $466,000 in the years 2001, 2000 and 1999, respectively.

o 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. These options have an expiration date 10 years from date of grant.

o 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. Unvested options are subject to forfeiture upon certain termination of employment events and expire 10 years from date of grant.

o The Company granted 533,000 stock options to employees on March 23, 2000 and 120,000 stock options to directors on July 25, 2000 at $10.50 per share. The March 23, 2000 grant was subject to shareholder approval of an amendment to the 1996 Stock Incentive Plan. The amendment, which was approved on May 9, 2000 at the Annual Meeting of Shareholders, increased the number of shares reserved for issuance under the 1996 plan to 2,200,000 shares. The excess of the market price over the exercise price on the approval date of the amendment is amortized over the three-year vesting period of the options. Compensation costs of $611,000 and $801,000 were recognized in income in 2001 and 2000 respectively related to these options.

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 unless the exercise price is less than the market price at the measurement date. Had compensation cost for these plans been determined consistent with Statement of Financial Accounting Standards No. 123 ("SFAS 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:

		2001	2000	1999
		(IN THOUSANDS, EXCEPT PER SHARE DATA)		
Net income (loss) available for common shares:	As Reported	$ 539	$ 10,144	$ 130
	Pro Forma	(839)	8,418	(1,212)
Basic earnings (loss) per share:	As Reported	.04	.82	.01
	Pro Forma	(.06)	.68	(.14)
Diluted earnings (loss) per share:	As Reported	.04	.80	.01

Pro Forma	(.06)	.66	(.14)

A summary of the status of the Company's two stock option plans for the three most recent years and changes during the years then ended is presented in the table and narrative below:

	2001		2000	
	SHARES	WTD AVG EX PRICE	SHARES	WTD AVG EX PRICE
Outstanding, beginning of year	2,304,167	$ 10.83	1,536,500	$ 10.60
Granted (at market)	30,000	11.61	135,000	14.73
Granted (below market)	--	--	653,000	10.50
Exercised	(1,500)	9.00	(20,333)	9.00
Forfeited	--	--	--	--
Expired	--	--	--	--
Outstanding, end of year	2,332,667	$ 10.84	2,304,167	$ 10.83
Exercisable, end of year	2,057,977	$ 10.80	1,647,657	$ 10.71
Weighted average fair value of options granted (at market)	$ 5.80		$ 7.68	
Weighted average fair value of options granted (below market)	N/A		$ 7.90	

At December 31, 2001, 2,157,667 of the 2,332,667 options outstanding have exercise prices between $9 and $13.50 with a weighted average exercise price of $10.53 and a weighted average remaining contractual life of 5.90 years. Of these options, 1,919,277 are exercisable at a weighted average exercise price of $10.53. The remaining 175,000 options have exercise prices between $13.50 and $15.31 with a weighted average exercise price of $14.69 and a weighted average remaining contractual life of 7.98 years. Of these options, 138,700 are exercisable at a weighted average exercise price of $14.61.

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 the years presented are as follows:

	2001	2000	1999
Risk free interest rate	4.5%	6.3%	6.3%
Expected life (years)	5.0	5.0	7.0
Expected volatility	43.9%	52.1%	46.0%
Expected dividends	--	--	--

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") for net proceeds of $30.9 million. 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.

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. Likewise in 2000, 444,600 shares of Preferred Stock were converted into 1,036,098 shares of the Company's Common Stock. 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.

In 2001, under the terms of the $95 million multiple advance loan, the Company issued warrants to purchase, at a nominal exercise price, 265,210 shares of its common stock. See Note 5.

The Company adopted a stockholder rights plan on March 30, 2000, designed to assure that the Company's stockholders receive fair and equal treatment in the event of any proposed takeover of the Company and to guard against partial tender offers, squeeze-outs, open market accumulations, and other abusive tactics to gain control without paying all stockholders a fair price. The rights plan was not adopted in response to any specific takeover proposal. Under the rights plan, the Company declared a dividend of one right ("Right") on each share of the Company's Common Stock. Each Right will entitle the holder to purchase one one-thousandth of a share of a Series B Preferred Stock, par value $0.01 per share, at an exercise price of $90 per one one-thousandth of a share. The Rights are not currently exercisable and will become exercisable only in the event a person or group acquires, or engages in a tender or exchange offer to acquire, beneficial ownership of 15 percent or more (one existing stockholder was granted an exception for up to 21 percent) of the Company's Common Stock. After the Rights become exercisable, each Right will also entitle its holder to purchase a number of common shares of the Company having a market value of twice the exercise price.

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The dividend distribution was made to stockholders of record at the close of business on April 10, 2000. The Rights will expire on March 30, 2010.

12. SUPPLEMENTAL OIL AND GAS RESERVE DATA (UNAUDITED)

The Company's proved oil and gas reserves at December 31, 2001, 2000 and 1999 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. These estimates have been adjusted (per SEC guidelines) to exclude the volumetric production payment described in Note 2.

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 standard measure of discounted future net cash flows 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.

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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,		
	2001	2000	1999
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	33,382	23,834	6,898
Revisions to previous estimates	(2,290)	85	(686)
Purchase of reserves in place	--	--	2,629
Sales of reserves in place	(624)	--	--
Extensions and discoveries	14	9,695	15,323
Production	(273)	(232)	(330)
End of period	30,209	33,382	23,834
Natural Gas (MMcf):			
Beginning of period	129,922	110,621	88,030
Revisions to previous estimates	(5,874)	(4,817)	(11,492)
Purchase of reserves in place	--	347	4,733
Sales of reserves in place	--	--	--

Extensions and discoveries	7,483	35,387	42,662
Production	(11,232)	(11,616)	(13,312)
End of period	120,299	129,922	110,621

Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	2,192	1,376	1,774
End of period	885	2,192	1,376
Natural Gas (MMcf):			
Beginning of period	63,982	76,295	76,895
End of period	51,221	63,982	76,295

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 ($2.58 for natural gas and $20.10 for oil for the 2001 disclosures) 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

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
		(IN THOUSANDS)	
Future cash inflows	$ 883,145	$ 2,080,680	$ 847,930
Future costs -			
Production	(220,857)	(284,667)	(207,615)
Development and net abandonment	(191,369)	(217,507)	(123,749)
Future net inflows before income taxes	470,919	1,578,506	516,567
Future income taxes	(30,315)	(472,637)	(109,238)
Future net cash flows	440,604	1,105,869	407,329
10% discount factor	(185,747)	(434,672)	(151,007)
Standardized measure of discounted			

future net cash flows	$ 254,857	$ 671,197	$ 256,322

CHANGES IN STANDARDIZED MEASURE

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
	(IN THOUSANDS)		
Standardized measure - beginning of period	$ 671,197	$ 256,322	$ 99,751
Sales and transfers, net of production costs	(45,672)	(42,132)	(27,076)
Net change in sales and transfer prices, Net of production costs	(604,391)	361,179	57,246
Exchange and sale of in place reserves	(5,850)	--	--
Purchases, extensions, discoveries, and improved recovery, net of future production and development costs	9,358	276,770	181,185
Revisions of quantity estimates	(23,314)	(12,399)	(22,438)
Accretion of discount	90,978	28,581	9,975
Net change in income taxes	224,290	(209,090)	(29,492)
Changes in production rates, timing and other	(61,739)	11,966	(12,829)
Standardized measure - end of period	$ 254,857	$ 671,197	$ 256,322

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13. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
	(IN THOUSANDS, EXCEPT PER SHARE DATA)			
2001				
Total revenues	$20,812	$17,712	$12,715	$10,513
Total costs and expenses	11,314	12,398	12,311	22,936
Income tax expense (benefit)	3,324	1,860	142	(4,349)
Net income	6,174	3,454	262	(8,074)
Net income per share-basic	0.44	0.24	0.00	(.63)
Net income per share-diluted	0.41	0.23	0.00	(.63)
2000				
Total revenues	$10,118	$14,716	$16,422	$16,821
Total costs and expenses	8,354	9,935	9,958	10,820
Income tax expense	600	1,626	2,197	2,040
Net income	1,164	3,155	4,267	3,961
Net income per share-basic	0.05	0.21	0.30	0.25
Net income per share-diluted	0.05	0.21	0.29	0.24

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 8, 2002 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 33 through 56.

Report of Independent Public Accountants

Consolidated Balance Sheets as of the Years Ended December 31, 2001 and 2000

Consolidated Statements of Operations for the Three Years in the Period Ended December 31, 2001

Consolidated Statements of Stockholders' Equity for the Three Years in the Period Ended December 31, 2001

Consolidated Statements of Cash Flows for the Three Years in the Period Ended December 31, 2001

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:

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, File No. 000-25192)

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)

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 Indenture for the Company's 10.125% Senior Subordinated Notes due 2002 dated as of July 31, 1997 (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed September 25, 1997, Reg. No. 333-36395)

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 14, 1999, Reg. No. 333-80579)

4.8 Rights Agreement between Callon Petroleum Company and American Stock Transfer & Trust Company, Rights Agent, dated March 30, 2000 (incorporated by reference from Exhibit 99.1 of the Company's Registration Statement on Form 8-A, filed April 6, 2000, File No. 001-14039)

4.9 Subordinated Indenture for the Company dated October 26, 2000 (incorporated by reference from Exhibit 4.1 of the Company's Current Report on Form 8-K dated October 24, 2000, File No. 001-14039)

4.10 Supplemental Indenture for the Company's 11% Senior Subordinated Notes due 2005 (incorporated by reference from Exhibit 4.2 of the Company's Current Report on Form 8-K dated October 24, 2000, File No. 001-14039)

4.11 Warrant dated as of June 29, 2001 entitling Duke Capital Partners, LLC to purchase common stock from the Company. (incorporated by reference to Exhibit 4.11 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

9. Voting trust agreement

None.

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)

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10.6 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)

10.7 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)

10.8 Callon Petroleum Company 1996 Stock Incentive Plan as amended on May 9, 2000 (incorporated by reference from Appendix I of the Company's Definitive Proxy Statement of Schedule 14A filed March 28, 2000)

10.9 Credit Agreement dated as of October 30, 2000 between the Company and First Union National Bank, as administrative agent for the lenders (incorporated by reference from Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2000, File No. 001-14039)

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10.12 Conveyance of Overriding Royalty Interest from the Company to Duke Capital Partners, LLC, dated June 29, 2001 (incorporated by reference to Exhibit 10.03 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2001, File No. 001-14039)

10.13 Callon Petroleum Company 2002 Stock Incentive Plan.

10.14 Change of Control Severance Compensation Agreement by and between Callon Petroleum and John S. Weatherly dated January 1, 2002.

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10.16 Change of Control Severance Compensation Agreement by and between Callon Petroleum Company and Dennis W. Christian, dated January 1, 2002.

11. Statement re computation of per share earnings*

12. Statements re computation of ratios*

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

16. Letter re change in certifying accountant*

18. Letter re change in accounting principles*

21. Subsidiaries of the Company

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

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

23. Consents of experts and counsel

23.1 Consent of Arthur Andersen LLP

24. Power of attorney*

99. Additional Exhibits

99.1 Letter to the Commission re: Arthur Andersen Representations

*Inapplicable to this filing.

(b) Reports on Form 8-K.

None

SIGNATURES

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

CALLON PETROLEUM COMPANY

Date: March 29, 2002	/s/ Fred L. Callon Fred L. Callon (principal executive officer, director)
Date: March 29, 2002	/s/ John S. Weatherly John S. Weatherly (principal financial officer)
Date: March 29, 2002	/s/ James O. Bassi James O. Bassi (principal accounting officer)
Date: March 29, 2002	/s/ John S. Callon John S. Callon (director)
Date: March 29, 2002	/s/ Dennis W. Christian Dennis W. Christian (director)

Date: March 29, 2002 /s/ B. F. Weatherly
B. F. Weatherly (director)

Date: March 29, 2002 /s/ Robert A. Stanger
Robert A. Stanger (director)

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

CALLON PETROLEUM COMPANY

Date: March 29, 2002 By: /s/ John S. Weatherly
John S. Weatherly, Senior Vice President and Chief Financial Officer

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