UNITED STATES
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, 2004**

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

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 ☑ . 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.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ☑ . No.☐ .

The aggregate market value of the voting and non-voting common equity held by nonaffiliates of the registrant was approximately $212.9 million as of June 30, 2004 (based on the last reported sale price of such stock on the New York Stock Exchange on such date of $14.26).

As of March 3, 2005, there were 17,720,866 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, 2004) relating to the Annual Meeting of Stockholders to be held on May 5, 2005 which is incorporated into Part III of this Form 10-K.

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PART I.

ITEM 1 and 2. BUSINESS and PROPERTIES

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. We were incorporated under the laws of the state of Delaware in 1994 and succeeded to the business of a publicly traded limited partnership, a joint venture with a consortium of European investors and an independent energy company owned by members of current management. 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 nine years, we have also placed emphasis on the acquisition of acreage with exploration and development drilling opportunities in the Gulf of Mexico shelf and deepwater areas. At December 31, 2004, we owned working interests in a total of 72 blocks/leases covering 145,000 net acres. To minimize risk we join with industry partners to explore federal offshore blocks acquired in the Gulf of Mexico. We perform extensive geological and geophysical studies using computer-aided exploration techniques (CAEX), including, where appropriate, the acquisition of 3-D seismic or high-resolution 2-D data to facilitate these efforts. We continue to develop prospects on the shelf through our 3-D seismic partnership using Amplitude versus Offset (“AVO”) technology. In 1998, we began exploration in the Gulf of Mexico deepwater area (generally 900 to 5,500 feet of water) and during the fourth quarter of 2003, our first two deepwater projects, the Medusa and Habanero fields, began production. Please see “Significant Properties” for a more detailed discussion.

We ended the year 2004 with estimated net proved reserves of 191 billion cubic feet of natural gas equivalent (“Bcfe”). This represents a decrease of 12% from 2003 year-end estimated net proved reserves of 217 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.

Availability of Reports

All of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to such reports as well as other filings we make pursuant to Section 13(a) and 15(d) of the Securities Exchange Act of 1934 are available free of charge on our Internet website. The address of our Internet website is www.callon.com. Our Securities and Exchange Commission (“SEC”) filings are available on our website as soon as they are posted to the EDGAR database on the SEC’s website.

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; and

- replenish our prospect inventory with increasing emphasis on prospect generation using AVO technology.

Exploration and Development Activities

Capital expenditures for exploration and development costs related to oil and gas properties totaled approximately $65 million in 2004. We incurred approximately $19 million in the Gulf of Mexico deepwater area primarily for continued development costs at our Habanero and Medusa discoveries and drilling of two satellite wells in the Medusa area. Interest of approximately $5 million and general and administrative costs allocable directly to exploration and development projects of $7 million were capitalized in 2004. Our Gulf of Mexico shelf area expenditures account for the remainder of the total capital expended, which includes the developmental drilling and completion of a shallow miocene well and a shelf well and the drilling of six exploratory shelf wells, one of which was completed in 2004. Two are scheduled for completion during early 2005.

Risk Factors

A 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, and 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 secured credit facility;

- the value of our oil and gas properties; and

- the profit or loss we incur in exploring for and developing our reserves.

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 annual report.

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 us to make 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 report. 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 report 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, 2004, approximately 44% of the discounted present value of our estimated net proved reserves were proved undeveloped. Proved undeveloped reserves represented 50% of total proved reserves. 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.

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 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 2004, 83% of our daily production came from four of our properties in the Gulf of Mexico. Moreover, one property accounted for 34% of our production during this period. In addition, at December 31, 2004, most of our proved reserves were located in three fields in the Gulf of Mexico, with approximately 82% of our total net proved reserves attributable to these properties. If mechanical problems, storms or other events curtailed a substantial portion of this production or if the actual reserves associated with any one of these producing properties 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.

We do not operate all of our properties and have limited influence over the operations of some of these properties, particularly our deepwater properties. 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. Deepwater drilling operations require the application of more advanced drilling technologies involving a higher risk of technological failure and usually have significantly higher drilling costs than shallow water drilling operations. Deepwater wells are completed using sub-sea 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. Deepwater discoveries require the construction of expensive production facilities and pipelines prior to 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, and 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 ¾ 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 secured credit facility to borrow funds to supplement our available cash. The amount we may borrow under our senior secured credit facility may not exceed a borrowing base determined by the lenders under such facility based on their projections of our future production, 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 secured 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 secured credit facility to reduce the outstanding amount to less than the borrowing base, we would be in default under our senior secured credit facility. For a description of our senior secured credit facility and its principal terms and conditions, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations ¾Liquidity and Capital Resources” and Note 5 to our Consolidated Financial Statements.

Our decision to drill a prospect is subject to a number of factors and we may decide to alter our drilling schedule or not drill at all. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect which will require substantial additional seismic data processing and interpretation. Whether we ultimately drill a prospect may depend on the following factors:

- receipt of additional seismic data or the reprocessing of existing data;
- material changes in oil or gas prices;
- the costs and availability of drilling rigs;
- the success or failure of wells drilled in similar formations or which would use the same production facilities;
- availability and cost of capital;
- changes in the estimates of the costs to drill or complete wells;
- our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks; and
- decisions of our joint working interest owners.

We will continue to gather data about our prospects and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all. You should understand that our plans regarding our prospects are subject to change.

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;
- 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; and
- because of these or other events, we could experience environmental hazards, including oil spills, gas leaks, and ruptures.

In the event of any of the foregoing, we may be subject to interrupted production or substantial environmental liability due to injury to or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damage, investigation and remediation requirements. Moreover, a substantial portion of our operations are offshore and are subject to a variety of risks peculiar to the marine environment such as capsizing, 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. We also enter into price “collars” to reduce the risk of changes in oil and gas prices. Under a collar, no payments are due by either party so long as the market price is above a floor set in the collar and below a ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to us and if the price is above the ceiling, we pay the counter-party the difference. Another type of hedging contract we have entered into is a put contract. Under a put, if the price falls below the set floor price, the counter-party to the contract pays the difference to us. 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 the 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 of the carrying value of our oil and gas properties. 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 which 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.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

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. We also maintain a business office in Houston, Texas, and own or lease 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 87 employees as of December 31, 2004, none of whom are currently represented by a union. We believe that we have good relations with our employees. We employ six petroleum engineers and seven 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 us 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, primarily pursuant to Order Nos. 436 and 636, 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.

In February, 2000, the FERC issued Order No. 637, a rule designed to continue the restructuring of the gas industry. Order No. 637 revised the FERC’s policies governing interstate pipeline transportation rates and penalties and refined the regulatory framework governing transportation terms and conditions to improve open access transportation. The rule has been implemented on a pipeline-by-pipeline basis in individual compliance proceedings, almost all of which have been settled or have otherwise been terminated.

In Order No. 2004, issued on November 25, 2003, the FERC issued standards of conduct covering regulated interstate pipelines and public utilities (“Transmission Providers”) to govern the relationships between regulated Transmission Providers and all of their energy affiliates. Among other things, these measures are intended to increase confidence and transparency in the gas market in the wake of recent events involving anticompetitive behavior and market abuse.

On February 12, 2004, the FERC issued a notice of proposed rulemaking in Docket No. RM04-4 designed to standardize the procedures for determining the creditworthiness and collateral required of shippers on interstate pipelines and to adopt certain standards published by the North American Energy Standards Board with respect to shipper creditworthiness. The standards are intended to facilitate and increase transparency in the creditworthiness evaluation process.

The FERC is presently reviewing in Docket No. PL04-3, a general policy inquiry, and in individual interstate gas pipeline proceedings, whether it should adopt quality and “interchangeability” standards for natural gas delivered through interstate pipelines. In general, the issue in these proceedings is whether the FERC should impose quality standards for individual pipelines or on a broader basis or otherwise regulate the composition and quality of natural gas transported through the interstate pipeline system. At the present time the approach that the FERC will take in these proceedings and the potential impact on gas supply and on the Company are not clear. In addition, on November 22, 2004, the FERC initiated an inquiry on selective discounting for shippers by interstate natural gas pipelines. The FERC is focusing the inquiry on whether such discounting should continue to be supported by the prices paid by other customers as is the case under current FERC policy. One key issue in this inquiry is whether the existing FERC policy should be continued for shippers who have access to more than one interstate gas pipeline. Because the inquiry has not been completed, its effect on the availability of discounted interstate pipeline transportation rates for shippers of natural gas is unclear.

On October 10, 2003, the U.S. Court of Appeals for the District of Columbia Circuit affirmed a district court ruling that severely circumscribed the FERC’s authority under the Outer Continental Shelf Lands Act (“OCSLA”). The court found that OCSLA confers upon the Secretary of Interior, not the FERC, authority to enforce open access conditions under OCSLA. The FERC retains authority under the Natural Gas Act (“NGA”) to enforce open access transportation conditions over natural gas pipeline facilities on the Outer Continental Shelf (“OCS”), and under limited conditions over natural gas gathering facilities owned directly or indirectly by natural gas pipeline companies. The FERC has no authority under the NGA to enforce open access conditions on gathering facilities owned by companies that are not affiliated with natural gas pipeline companies. The FERC has no authority under the Interstate Commerce Act (“ICA”) to regulate oil pipelines that lie wholly on the OCS. In response to the court’s opinion, on April 12, 2004 the Minerals Management Service (“MMS”) of the Department of Interior (“DOI”) issued an Advanced Notice of Proposed Rulemaking (ANOPR”) requesting comments to assist it in potentially amending its regulations regarding how the DOI should ensure that pipelines transporting oil or gas under permits, licenses, easements or rights-of-way across the OCS provide open and non-discriminatory access to both owner and non-owner shippers under OCSLA. Various parties filed comments in response to the ANOPR. The MMS has not yet issued a follow-up Notice of Proposed Rulemaking. It is not clear what regulatory regime the MMS will impose to enforce open access transportation on the OCS under OCSLA, nor what impact any particular regulatory regime may have upon the ability of the Company to obtain transportation of its natural gas and oil production to markets.

Sales and Transportation of Crude Oil. Sales of crude oil and condensate can be made by us at market prices not subject at this time to price controls. The price that we receive 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 interstate pipelines are regulated by the FERC under the ICA. Pursuant to the Energy Policy Act of 1992, which “grandfathered” certain existing rates, the FERC presently regulates interstate oil pipeline rates under a light-handed, streamlined regulatory regime where interstate pipeline rates can be adjusted annually using an index ceiling based upon the producer price index. The FERC recently modified the formula for calculating the index such that the index ceilings are now set slightly higher than under the original formula. 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 have had on moving our production to market has not been material.

As stated above, as a result of a recent decision by the U.S. Court of Appeals for the District of Columbia Circuit with respect to the transportation of oil and condensate on or across the OCS, the DOI, not the FERC, has the authority under OCSLA to enforce open access conditions on oil pipelines lying wholly on the OCS.

Legislative Proposals. In the past, Congress has been 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 difficult 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 our operations.

Federal, State or Indian Leases. In the event we conduct 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 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 our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our 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 we sell our production in the spot market and therefore pay royalties on production from federal leases, it is not anticipated that this final rule will have any substantial impact on us.

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. We own interests in numerous federal onshore oil and gas leases. It is possible that some of our stockholders 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.

We 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 we 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, installing and operating such facilities. The impact of such pipeline safety regulations would not be any more adverse to us than it would be to other similar owners or operators of such pipeline facilities.

Environmental Regulations

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

Our activities 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, installing and operating such facilities. In most instances, the regulatory requirements relate to water and air pollution control measures. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, 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 us.

Solid and Hazardous Waste. We currently own or lease, and in the past owned or leased, properties that have been used for the exploration and production of oil and gas for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties. We have 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 new laws, we could be required to remediate property, including groundwater, containing or impacted by 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 or mitigate existing contamination.

We generate wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under the RCRA and similar state statutes ("Hazardous Wastes"). Furthermore, it is possible that certain wastes generated by our oil and gas operations that are currently exempt from treatment as Hazardous Wastes 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 federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRPs"), include the current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of 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 PRPs the costs of such action. Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, we have generated and will generate wastes that may fall within CERCLA's definition of Hazardous Substance. We may also be the owner or operator of sites on which Hazardous Substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA. We also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. Certain states, including Louisiana, have comparable statutes. In the event contamination is discovered at a site on which we are or have been an owner or operator, we could be liable for costs of investigation and remediation and natural resource damages.

Clean Water Act. The Clean Water Act ("CWA") imposes restrictions and strict controls regarding the discharge of wastes including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into federal waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and hazardous substances and of other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances and other pollutants. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require us to obtain permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, we may be liable for penalties and costs.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of the CWA, imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. The OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses and limitations exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

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. We believe that we have established adequate proof of financial responsibility for our offshore facilities.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require us to forego construction, modification or operation of certain air emission sources.

Coastal Coordination. There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act (“CZMA”) was passed in 1972 to preserve and, where possible, restore the natural resources of the Nation’s coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development.

Various states, such as Alabama, Louisiana and Texas, also have coastal management programs, which provide for, among other things, the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. Coastal management programs also may provide for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the state coastal management plan. This review may impact agency permitting and review activities and add an additional layer of review to certain activities undertaken by us.

OSHA and other Regulations. We are 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 CERCLA and similar state statutes require us to organize and/or disclose information about hazardous materials used, stored or produced in our operations.

Our management believes that we are 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 us.

Commitments and Contingencies

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 person, and the environment resulting from the Company's operations could have on its activities.

Property Summary

We are engaged in the exploration, development, acquisition and production of oil and gas properties 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 increased our reserves and production by focusing primarily on low to moderate risk exploration and acquisition opportunities in the Gulf of Mexico shelf area. In 1998, we expanded our area of exploration to include the Gulf of Mexico deepwater area. As of December 31, 2004, our estimated net proved reserves totaled 19.7 million barrels of oil ("MMBbl") and 72.6 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 $612.6 million. Oil constitutes approximately 62% on an equivalent basis of our total estimated proved reserves and approximately 50% of our total estimated proved reserves are proved developed reserves.

Our Medusa (Mississippi Canyon Blocks 538/582) and Habanero (Garden Banks Block 341) discoveries began production in the fourth quarter of 2003. A detailed discussion of each of these properties is provided in the "Significant Properties" section of this report. These two deepwater discoveries were primarily responsible for an increase in our 2004 production by approximately 57% from 2003 levels.

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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 the focus area, for our eight largest fields and for all other properties combined at December 31, 2004.

		Estimated Net Proved Reserves			Pre-tax Discounted Present Value ($000) (a)(b)
	Operator	Oil (MBbls)	Gas (MMcf)	Total (MMcfe)	
Gulf of Mexico Deepwater:					
Mississippi Canyon Blocks 538/582 “Medusa”	Murphy	6,945	4,970	46,640	$ 155,829
Garden Banks Block 341 “Habanero”	Shell	4,070	10,390	34,812	139,153
Garden Banks Blocks 738/782/826/827 “Entrada”	BP	7,772	29,126	75,760	219,368
Gulf of Mexico Shelf:					
Mobile Blocks 863/864/907/908	Callon	—	4,068	4,068	9,929
Mobile Blocks 952/953/955	Callon	—	9,362	9,362	29,199
North Padre Island Block 913	Callon	2	3,457	3,467	11,133
High Island Block 119	Kerr-McGee	32	2,999	3,192	18,560
Onshore and Other:					
Big Escambia Creek	Vintage	387	1,627	3,949	8,970
Other	Various	540	6,620	9,858	20,454
Total Net Proved Reserves		19,748	72,619	191,108	$ 612,595

(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, 2004, as set forth in the Company’s reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc. of Houston, Texas.

(b) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2004, in accordance with Statement of Financial Accounting Standards No. 143. See the Oil and Gas Reserve table for the standardized measure of discounted future net cash flow which is a required calculation by the SEC.

Gulf of Mexico Deepwater

Medusa, Mississippi Canyon Blocks 538/582

Our Medusa deepwater discovery was announced in September 1999, after 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. Subsequent sidetrack drilling from the wellbore was used to determine the extent of the discovery and a second well was drilled in the first quarter of 2000 to further delineate the extent of the pay intervals. We own a 15% working interest, Murphy Exploration & Production Company, the operator, owns a 60% working interest and ENI Deepwater, LLC, owns the remaining 25% working interest.

In 2001 a drilling program began which included four development wells and one sidetrack. The program included production casing being set on six wells to provide initial production take-points and was completed in the first half of 2002. The construction of a floating production system, spar, at Medusa was completed during the second quarter of 2003. The A-1 well was completed and tied into the spar and commenced production in late November 2003. The remaining five wells were completed and commenced production in 2004. During 2004 the field produced an average of 20.5 million cubic feet of natural gas equivalent (“MMcfe”) per day net to us. The field is currently producing approximately 40,000 barrels of crude oil and 40 million cubic feet of natural gas (“MMcf”) per day, or 36.1 MMcfe per day net to our interest.

In December 2003, we transferred our undivided 15% working interest in the spar production facilities to Medusa Spar LLC in exchange for cash proceeds of approximately $25 million and a 10% ownership interest in the LLC. A detailed discussion of this transaction is included in Management’s Discussion and Analysis of Financial Condition and Results of Operations-“Off-Balance Sheet Arrangements”.

Habanero, Garden Banks Block 341

During February 1999, the initial test well on our Habanero deepwater discovery encountered over 200 feet of net pay in two zones. Located in 2,000 feet of water, the well was drilled to a measured depth of 21,158 feet. We own an 11.25% working interest in the well. The well 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 mid-year 2001, which included three sidetracks of the discovery well. Production casing was set on this well through one of the sidetracks to the Habanero 52 oil and gas sand and the Habanero 55 gas sand. Also, a development well was drilled in the summer of 2003 which provides a take-point for production from the Habanero 52 oil sand. By means of a sub-sea completion and tie back to an existing production facility in the area operated by Shell, production from the Habanero 52 oil sand commenced in late November 2003 and from the Habanero 55 gas sand in January 2004. In July the #2 well producing the Habanero 52 oil sand developed mechanical difficulties with a subsurface control value and was shut-in resulting in a significant loss of production. Repairs were completed and production was restored in late December. In addition, the #1 well producing the Habanero 55 gas sand was recompleted to the Habanero 55 oil sand in December. Our net production during 2004 from the Habanero field was approximately 11.1 MMcfe per day. The field is currently producing approximately 21,000 barrels of crude oil and 35 MMcf per day, or 15.5 MMcfe per day net to our interest.

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. The Entrada Area is characterized by a northwest plunging salt ridge with multiple stacked amplitudes trapped against the salt and various faults. We own a 20% working interest in this discovery with BP, the operator, holding the remaining working interest.

An integrated project team has been formed by the working interest owners and is reviewing various plans for development of the field. One scenario is to negotiate a tie-in of Entrada into existing production facilities. The owners of an adjacent discovery have commenced production from facilities that will enable them to be a regional off-take point in Southeastern Garden Banks. These plans include handling third party tie-ins. Production from Entrada under this scenario could possibly commence in 2007.

Gulf of Mexico Shelf

Mobile Blocks 863/864/ 907

We own an average 64.6% working interest in these blocks and we are the operator. The Mobile 864 unit, in which we have a 66.4% working interest, has four producing wells, unit production facilities and covers portions of these three blocks. During 2004 the unit produced an average of 2.9 MMcf per day net to us.

Mobile Blocks 952/953/955

We own a 100% working interest in these three blocks and we are the operator. In the fourth quarter of 2001, we initiated a production acceleration program for Mobile Blocks 952, 953 and 955, which were being produced through the Mobile Block 864 unit facilities and were production constrained. An acceleration well was successfully drilled in the fourth quarter of 2001 and stand-alone production facilities were installed and production flow lines were rerouted to the new facilities. Production commenced through the new facilities in April 2002. In order to completely produce the proved reserves of the field we drilled a development well on Mobile Block 955 during the first quarter of 2004. Production from the field for 2004 was 14.7 MMcf per day net to us.

High Island Block 119

An initial exploratory well and one development well were drilled and completed in 2004. First production began in the third quarter of 2004. An exploratory well in an offsetting fault block was spud late in the fourth quarter of 2004 and was completed in 2005. We own a 22% working interest and Westport Resources is the operator. Production for the fourth quarter of 2004 net to us was 3.7 MMcfe per day. Peak production should be reached by the end of the first quarter of 2005 at a rate estimated to be 50 MMcfe per day, or 8.5 MMcfe per day net to our interest.

North Padre Island Block 913

An exploratory well was drilled to a vertical depth of 8,082 feet in the fourth quarter of 2004 and found apparent natural gas pay in multiple intervals. Currently, the well is being completed and will be tied back to existing infrastructure on a nearby block. We are the operator and own a 50% working interest. First production is forecast to be in the third quarter of 2005.

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Onshore and Other

Big Escambia Creek

This gas field in south Alabama produces from the Smackover formation at depths ranging from 15,100 to 15,600 feet and is operated by Vintage. We own an average working interest of 4.9% (5.5% net revenue interest), in six wells and a 2.2% average royalty interest in another five wells. This field produced 0.7 MMcfe per day net to our interest in 2004. The field has an estimated reserve life in excess of 10 years given current production rates.

Other

We own various royalty and working interests in numerous onshore areas and the Gulf of Mexico other than the fields discussed above.

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,		
	2004	2003	2002
		(In thousands)	
Proved developed:			
Oil (Bbls)	10,292	9,919	1,056
Gas (Mcf)	33,982	31,415	37,631
Mcfe	95,735	90,926	43,966
Proved undeveloped:			
Oil (Bbls)	9,456	13,790	22,987
Gas (Mcf)	38,637	43,276	53,908
Mcfe	95,373	126,017	191,833
Total proved:			
Oil (Bbls)	19,748	23,709	24,043
Gas (Mcf)	72,619	74,691	91,539
Mcfe	191,108	216,943	235,799
Estimated pre-tax future net cash flows (a)	$892,145	$ 838,847	$970,199
Pre-tax discounted present value (a)	$612,595	$ 570,463	$623,946
Standardized measure of discounted future net cash flows(a)	$515,893	$ 519,026	$556,046

(a) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2004, in accordance with Statement of Financial Accounting Standards No. 143.

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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. 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 could be 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 during our last fiscal year.

Present Activities and 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 primarily in federal and state waters in the Gulf of Mexico.

	Years Ended December 31,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	—	—	2	.23	2	.30
Gas	2	1.22	—	—	—	—
Non-productive	—	—	—	—	1	.40
Total	2	1.22	2	.23	3	.70
Exploration:						
Oil	—	—	1	.15	—	—
Gas	2	.72	—	—	1	.22
Non-productive	5	1.24	1	.20	1	.50
Total	7	1.96	2	.35	2	.72

The following table sets forth our productive wells as of December 31, 2004:

	Wells	
	Gross	Net
Oil:		
Working interest	46.00	4.06
Royalty interest	189.00	3.15
Total	235.00	7.21
Gas:		
Working interest	39.00	17.34
Royalty interest	214.00	1.69
Total	253.00	19.03

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, 2004, we had no wells with multiple completions. At December 31, 2004, we had 1 gross (0.15 net) development oil well and 1 gross (0.22 net) exploration gas well in progress.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2004.

	Leasehold Acreage			
	Developed		Undeveloped	
Location	Gross	Net	Gross	Net
Louisiana	6,060	3,952	5,386	3,173
Other states	—	—	681	509
Federal waters	96,743	66,400	266,380	70,802
Total	102,803	70,352	272,447	74,484

As of December 31, 2004, we owned various royalty and overriding royalty interests in 1,336 net developed and 6,862 net undeveloped acres. In addition, we owned 4,157 developed and 121,843 undeveloped mineral acres.

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Major Customers

Our production is sold generally 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 12-month periods ended:

	December 31,		
	2004	2003	2002
Petrocom Energy Group, Ltd.	—	4%	4%
Dynegy	—	5%	7%
Prior Energy Corporation	—	20%	—
Reliant Energy Services	6%	28%	70%
Louis Dreyfus Energy Services	23%	27%	—
Shell Trading Company	30%	—	—
Plains Marketing, L.P.	13%	—	—
Conoco Phillips Company	8%	—	—
Chevron Texaco Natural Gas	6%	—	—

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 2004.

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
2003:		
First quarter	$ 4.35	$ 3.35
Second quarter	8.44	3.66
Third quarter	7.95	5.46
Fourth quarter	11.48	7.31
2004:		
First quarter	$ 11.23	$ 8.70
Second quarter	14.27	10.15
Third quarter	14.40	11.10
Fourth quarter	14.72	12.30

As of March 3, 2005, there were approximately 4,337 common stockholders of record.

We have never 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 prohibit the payment of cash 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, 2004 has 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.

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

	Years Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
Statement of Operations Data:					
Operating revenues:					
Oil and gas sales	$119,802	$ 73,697	$61,171	$60,010	$56,310
Operating expenses:					
Lease operating expenses	22,308	11,301	11,030	11,252	9,339
Depreciation, depletion and amortization	47,453	28,253	27,096	21,081	17,153
General and administrative	8,758	4,713	4,705	4,635	4,155
Accretion expense	3,400	2,884	—	—	—
Derivative expense	1,371	535	708	—	—
Total operating expenses	83,290	47,686	43,539	36,968	30,647
Income (loss) from operations	36,512	26,011	17,632	23,042	25,663
Other (income) expenses:					
Interest expense	20,137	30,614	26,140	12,805	8,420
Other (income)	(357)	(444)	(1,004)	(1,742)	(1,767)
Loss on early extinguishment of debt	3,004	5,573	—	—	—
Gain on sale of pipeline	—	—	(2,454)	—	—
Gain on sale of Enron derivatives	—	—	(2,479)	—	—
Writedown of Enron derivatives	—	—	—	9,186	—
Total other (income) expenses	22,784	35,743	20,203	20,249	6,653
Income (loss) before income taxes	13,728	(9,732)	(2,571)	2,793	19,010
Income tax expense (benefit)	(6,697)	8,432	(900)	977	6,463
Income (loss) before Medusa Spar LLC and cumulative effect of change in accounting principle	20,425	(18,164)	(1,671)	1,816	12,547
Income (loss) on Medusa Spar LLC, net of tax	1,076	(8)	—	—	—
Income (loss) before cumulative effect of change in accounting principle	21,501	(18,172)	(1,671)	1,816	12,547
Cumulative effect of change in accounting principle, net of tax	—	181	—	—	—
Net income (loss)	21,501	(17,991)	(1,671)	1,816	12,547
Preferred stock dividends	1,272	1,277	1,277	1,277	2,403
Net income (loss) available to common shares	$ 20,229	$(19,268)	$ (2 ,948)	$ 539	$10,144

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

	Years Ended December 31,				
	2004	2003	2002	2001	2000
Net income (loss) available to common shares	$ 20,229	$ (19,268)	$ (2,948)	$ 539	$ 10,144
Net income (loss) per common share:					
Basic:					
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.28	$ (1.42)	$ (.22)	$ .04	$ .82
Cumulative effect of change in accounting principle, net of tax	—	.01	—	—	—
Net income (loss) available to common	$ 1.28	$ (1.41)	$ (.22)	$ .04	$ .82
Diluted:					
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.22	$ (1.42)	$ (.22)	$ .04	$ .80
Cumulative effect of change in accounting principle, net of tax	—	.01	—	—	—
Net income (loss) available to common	$ 1.22	$ (1.41)	$ (.22)	$ .04	$ .80
Shares used in computing net income (loss) per common share:					
Basic	15,796	13,662	13,387	13,273	12,420
Diluted	17,678	13,662	13,387	13,366	12,745
Balance Sheet Data (end of period):					
Oil and gas properties, net	$406,690	$390,163	$377,661	$343,158	$258,613
Total assets	$457,523	$496,032	$410,613	$372,095	$301,569
Long-term debt, less current portion	$192,351	$214,885	$248,269	$161,733	$134,000
Stockholders' equity	$198,312	$133,261	$140,960	$147,224	$136,328

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.

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 Consolidated 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

We have 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.

Significant events of our financial and operating results for the year ended December 31, 2004 included:

- an increase in 2004 production and revenues of 57% and 63%, respectively, over 2003 levels;
- borrowing an additional $15 million for a term of seven years at an interest rate of 9.75% pursuant to a senior unsecured credit agreement;
- closing a three-year senior secured credit facility with an initial borrowing base of $60 million which can be increased to a maximum of $175 million;
- closing the public offering of 3,450,000 shares of common stock priced at $13.25 per share raising net proceeds of approximately $44 million, after expenses;
- sub-debt redemptions and bank line paydown; and
- an income tax benefit of $6.7 million as the result of reversing a valuation allowance which was established in 2003 against our deferred tax assets. See Note 3 to the Company's Consolidated Financial Statements for a more detailed discussion.

The additional borrowing pursuant to our 9.75% senior unsecured credit agreement and the public offering of shares of our common stock allowed us to redeem $33 million of senior subordinated notes which were maturing in 2005, redeem $10 million of 12% loans maturing in March 2005 and reduce the outstanding balance under our senior secured credit facility. In addition, excess funds were used for general corporate purposes. As a result, we expect that planned 2005 capital expenditures of approximately $80 million will be funded with cash flows from operations. The current borrowing base is $60 million under the senior secured credit facility and $52.7 million was available on December 31, 2004. For a more detailed discussion of outstanding debt see Note 5 to our Consolidated Financial Statements.

Our estimated net proved oil and gas reserves decreased at December 31, 2004 to 191 Bcfe. This represents a decrease of 12% from previous year-end 2003 estimated proved reserves of 217 Bcfe.

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 to our Consolidated Financial Statements 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 43% of the budgeted 2005 production and 38% of proved reserves at year-end 2004.

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

On December 16, 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004), ("SFAS 123R") Share-Based Payment, which is a revision of Statement of Financial Accounting Standards No. 123, ("SFAS 123") *Accounting for Stock-Based Compensation*. SFAS 123R supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and amends Statement of Financial Accounting Standards No. 95, *Statement of Cash Flows*. Generally, the approach in SFAS 123R is similar to the approach described in SFAS 123. However, SFAS 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro forma disclosure is no longer an alternative.

SFAS 123R must be adopted no later than July 1, 2005. Early adoption will be permitted in periods in which financial statements have not yet been issued. SFAS 123R permits public companies to adopt its requirements using one of two methods below:

- A "modified prospective" method in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS 123R for all share-based payments granted after the effective date and (b) based on the requirements of SFAS 123 for all awards granted to employees prior to the effective date of SFAS 123R that remain unvested on the effective date; or

- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

We expect to adopt SFAS 123R on July 1, 2005 using the modified prospective method.

As permitted by SFAS 123, we currently accounts for share-based payments to employees using Opinion 25's intrinsic value method and, as such, generally recognizes no compensation cost for employee stock options. Accordingly, the adoption of SFAS 123R's fair value method will have a significant impact on our result of operations, although it will have no impact on our overall financial position. The impact of adoption of SFAS 123R cannot be predicted at this time because it will depend on levels of share-based payments granted in the future. However, had we adopted SFAS 123R in prior periods, the impact of that standard would have approximated the impact of SFAS 123 as described in the disclosure of pro forma net income and earnings per share in Note 2 to our consolidated financial statements.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) 51" ("FIN 46"). FIN 46 addresses consolidation by business enterprises of variable interest entities ("VIEs"). We adopted FIN 46, as revised, as of December 31, 2003, which had no impact on our results of operations or financial position.

In September 2004, the SEC issued Staff Accounting Bulletin ("SAB") No. 106 which expressed the Staff's views regarding the application of Statement of Financial Accounting Standards ("SFAS") No. 143 "Accounting for Asset Retirement Obligations" by oil and gas producing companies following full-cost accounting method. SAB No. 106 specifies that subsequent to the adoption of SFAS No. 143 an oil and gas company following the full-cost method of accounting should include assets recorded in connection with the recognition of an asset retirement obligation pursuant to SFAS No. 143 as part of the costs subject to the full -cost ceiling limitation. The future cash outflows associated with settling the recorded asset retirement obligations should be excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test. The Company will be required to adopt the provisions of SAB No. 106 prospectively in the first quarter of 2005 which will have no impact on our results of operations or financial position.

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 into the “full-cost pool.” The amounts we capitalize into the full-cost pool are depleted (charged against earnings) using the unit-of-production method. The full-cost method of accounting for our proved oil and gas properties requires that we make estimates based on assumptions as to future events which could change. These estimates are described below.

Depreciation, Depletion and Amortization (DD&A) of Oil and Gas Properties. We calculate depletion by using the capitalized costs in our full-cost pool plus future development and abandonment costs (combined, the depletable base) and our estimated net proved reserve quantities. Capitalized costs added to the full-cost pool and other costs added to the depletable base include the following:

- the cost of drilling and equipping productive wells, dry hole costs, acquisition costs of properties with proved reserves, delay rentals and other costs related to exploration and development of our oil and gas properties;

- our payroll and general and administrative costs and costs related to 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 of oil and gas or our general corporate overhead;

- costs associated with properties that do not have proved reserves attributed to them are excluded from the full-cost pool. These unevaluated property costs are added to the full-cost pool at such time as wells are completed on the properties, the properties are sold or we determine these costs have been impaired. Our determination that a property has or has not been impaired (which is discussed below) requires that we make assumptions about future events;

- our estimates of future costs to develop proved properties are added to the full-cost pool for purposes of the DD&A computation. We use assumptions based on the latest geologic, engineering, regulatory and cost data available to us to estimate these amounts. However, the estimates we make are subjective and may change over time. Our estimates of future development costs are periodically updated as additional information becomes available; and

- prior to the adoption of SFAS 143, estimated costs to dismantle, abandon and restore a proved property were added to the full-cost pool for the purposes of DD&A. Subsequent to the adoption of SFAS 143, effective January 1, 2003, these costs are included in the full-cost pool. Such cost estimates are periodically updated as additional information becomes available. As discussed below, specifically SFAS 143, beginning January 1, 2003, we changed the method for which we account for such costs.

Capitalized costs included in the full-cost pool are depleted and charged against earnings using the unit of production method. Under this method, we estimate our quantity of proved reserves at the beginning of each accounting period. For each barrel of oil equivalent produced during the period, we record a depletion charge equal to the amount included in the depletable base (net of accumulated depreciation, depletion and amortization) divided by our estimated net proved reserve quantities.

Because we use estimates and assumptions to calculate proved reserves (as discussed below) and the amounts included in the full-cost pool, our depletion calculations will change if the estimates and assumptions are not realized. Such changes may be material.

Ceiling Test. Under the full-cost accounting rules, capitalized costs included in the full-cost pool, net of accumulated depreciation, depletion and amortization (DD&A), cost of unevaluated properties 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%, 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 that, in estimating future net cash flow, we assume that future oil and gas production will be sold at the unescalated market price for oil and gas received at the end of each fiscal quarter and that future costs to produce oil and gas will remain constant at the prices in effect at the end of the fiscal quarter. We are required to write-down and charge to earnings the amount, if any, by which these costs exceed the discounted future net cash flows, unless prices recover sufficiently before the date of our financial statements. Given the volatility of oil and gas prices, it is likely that our estimates of discounted future net cash flows from proved oil and gas reserves will change in the near term. If oil and gas prices 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.

Estimating Reserves and Present Values. Our estimates of quantities of proved oil and gas reserves and the discounted present value of such reserves at the end of each quarter are based on numerous assumptions which are likely to change over time. These assumptions include:

- the prices at which we can sell our oil and gas production in the future. Oil and gas prices are volatile, but we are generally required to assume that they will not change from the prices in effect at the end of the quarter. In general, higher oil and gas prices will increase quantities of proved reserves and the present value of such reserves, while lower prices will decrease these amounts. Because our properties have relatively short productive lives, changes in prices will affect the present value more than quantities of oil and gas reserves;

- the costs to develop and produce our reserves and the costs to dismantle our production facilities when reserves are depleted. These costs are likely to change over time, but we are required to assume that costs in effect at the end of the quarter will not change. Increases in costs will reduce oil and gas quantities and present values, while decreases in costs will increase such amounts. Because our properties have relatively short productive lives, changes in costs will affect the present value more than quantities of oil and gas reserves; and

- the liability to pay royalties to the Mineral Management Service. See Note 7 of our Consolidated Financial Statements for a more detailed discussion of this potential liability.

In addition, the process of estimating proved oil and gas reserves requires that our independent and internal reserve engineers exercise judgment based on available geological, geophysical and technical information. We have described the risks associated with reserve estimation and the volatility of oil and gas prices, under “Risk Factors”.

Unproved Properties. Costs associated with properties that do not have proved reserves, including capitalized interest, are excluded from the full-cost pool. These unproved properties are included in the line item “Unevaluated properties excluded from amortization.” Unproved property costs are transferred to the full-cost pool when wells are completed on the properties or the properties are sold. In addition, we are required to determine whether our unproved properties are impaired and, if so, add the costs of such properties to the full-cost pool. We determine whether an unproved property should be impaired by periodically reviewing our exploration program on a property by property basis. This determination may require the exercise of substantial judgment by our management.

Asset Retirement Obligations. In June 2001, the FASB issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (“SFAS 143”) effective for fiscal years beginning after June 15, 2002. SFAS 143 essentially requires entities to record the fair value of a liability for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. We adopted the statement on January 1, 2003 resulting in a cumulative effect of accounting change of $181,000, net of tax. See Note 8 to our Consolidated Financial Statements.

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. We currently use the accounting treatment for derivatives specified under SFAS 133.
See Note 6 to our Consolidated Financial Statements.

Income Taxes. We follow 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.

SFAS 109 provides for the weighing of positive and negative evidence in determining whether it is more likely than not that a deferred tax asset is recoverable. We incurred losses in 2002 and 2003 and had losses on an aggregate basis for the three-year period ended December 31, 2003. Because of these cumulative losses we established a full valuation allowance of $11.5 million as of December 31, 2003.

As a result of production from our first two deepwater projects starting in November 2003, as well as refinancing our highest cost debt in 2004, we achieved profitable operations and have income on an aggregate basis for the three-year period ended December 31, 2004. We also expect 2005 production levels to exceed 2004 levels and expect to utilize most if not all of the deferred tax asset in 2005. As a result, we have reversed the valuation allowance which had a balance of $7.0 million as of December 31, 2004. See Note 3 to the Consolidated Financial Statements for further disclosure.

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 2004 to $3.3 million, down $5.4 million. Cash provided from operating activities during 2004 totaled $70.9 million, up 106% from $34.6 million in 2003. Dividends paid on preferred stock were $1.3 million. All of our outstanding debt was restructured during December 2003 and the first half of 2004. The restructuring is discussed in the following paragraphs.

In December 2003 we borrowed $185 million pursuant to a senior unsecured credit facility with a stated interest rate of 9.75%. In conjunction with the new senior unsecured notes, we issued detachable warrants to purchase 2.775 million shares of our common stock at an exercise price of $10 per share and an expiration date in December 2010. This senior unsecured debt matures December 8, 2010. The net proceeds from the loans of $181.3 million were used to redeem $22.9 million of 10.125% senior subordinated notes due July 31, 2004 (“10.125% notes”), $40 million of 10.25% senior subordinated notes due September 15, 2004 (“10.25% notes”), $85 million of our 12% loans due March 31, 2005 (“12% loans”) plus a 1% call premium of $850,000 and to reduce the balance outstanding under our senior secured revolving credit facility. A charge of $5.6 million was incurred in 2003 and a charge of approximately $1.9 million was incurred in 2004 as a result of the early extinguishment of debt. We exercised covenant defeasance under the indentures for the 10.125% and 10.25% notes on December 8, 2003 and distributed a required 30-day redemption notice. The funds necessary to redeem the notes were placed in trust and the trustee paid the holders of the notes on January 8, 2004. The funds in trust were classified on our December 31, 2003 balance sheet as restricted cash.

During March 2004, we borrowed an additional $15 million under our 9.75% senior unsecured credit facility bringing the total outstanding to $200 million. The net proceeds of approximately $14 million were primarily used to retire the remaining $10 million of 12% loans plus a 1% call premium of $100,000. A charge of $559,000 was incurred as a result of early extinguishment of debt.

In March 2004, the $200 million in aggregate principal amount of loans outstanding under the 9.75% senior unsecured credit facility were exchanged for 9.75% Senior Notes due 2010, Series A, “Series A notes”, issued pursuant to a senior indenture between us and American Stock Transfer & Trust Company dated March 15, 2004. On August 12, 2004, we completed an offer to exchange our 9.75% Senior Notes due 2010, Series B, that have been registered under the Securities Act of 1933, for all outstanding Series A notes. See Note 5 of our Consolidated Financial Statements for a more detailed description of these notes.

On June 15, 2004, we closed on a three-year senior secured credit facility underwritten by Union Bank of California, N.A. The credit facility includes an initial borrowing base, determined by the lender, of $60 million, which may be adjusted semi-annually and could increase to a maximum of $175 million. At closing, $21 million was advanced under the new facility for repayment of the existing debt under the expiring credit facility with Wachovia Bank, National Association. As of December 31, 2004 there was $5.0 million outstanding under the facility and we had an aggregate of $2.3 million in outstanding letters of credit issued under the credit facility. These letters of credit secure obligations under the outstanding hedging contracts described in Note 6 to the Consolidated Financial Statements. The outstanding letters of credit reduce the amount available for borrowings under the credit facility. As a result, $52.7 million was available for future borrowings under the credit facility as of December 31, 2004.

On June 22, 2004, we closed the public offering of three million shares of common stock priced at $13.25 per share raising net proceeds of approximately $38.2 million, after expenses. In addition, we granted the underwriter, Johnson Rice & Company L.L.C., an over-allotment option to purchase an additional 450,000 shares. On June 30, 2004, the underwriter exercised the over-allotment option for an additional 450,000 shares priced at $13.25 per share, raising the net proceeds of the offering by approximately $5.7 million, after expenses. The proceeds from the transactions were used to redeem $33 million of our 11% Senior Subordinated Notes due December 15, 2005 to reduce the balance outstanding under our senior secured credit facility and general corporate purposes.

Outstanding debt on December 31, 2004 was $192.9 million compared to $308.1 million on December 31, 2003. Restricted cash in the amount of $62.9 million was used to payoff 2004 Senior Subordinated Notes on January 8, 2004 which were included in outstanding debt on December 31, 2003. The senior secured credit facility and our senior notes contain various covenants including restrictions on additional indebtedness and payment of cash dividends as well as maintenance of certain financial ratios. We were in compliance with these covenants at December 31, 2004.

In December 2003, we announced the formation of a limited liability company, Medusa Spar LLC, which now owns a 75% undivided ownership interest in the deepwater spar production facilities on our Medusa Field in the Gulf of Mexico. We contributed a 15% undivided ownership interest in the production facility to the LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. Our cash proceeds were used to reduce the balance outstanding under our senior secured credit facility. The LLC will earn a tariff based upon production volume throughput from the Medusa area. We are obligated to process our share of production from the Medusa Field and any future discoveries in the area through the spar production facilities. The LLC used the cash proceeds from $83.7 million of non-recourse financing and a cash contribution by one of the LLC owners to acquire its 75% interest in the spar. On December 31, 2004, $64.1 million of this financing was outstanding. The balance of the LLC is owned by Oceaneering International, Inc. (NYSE:OII) and Murphy Oil Corporation (NYSE:MUR). We are accounting for our 10% ownership interest in the LLC under the equity method.

Our planned capital expenditures for 2005 total $80 million. We anticipate that cash flow generated during 2005 will fund these expenditures and the current portion of our asset retirement obligation in the amount of $13.3 million. Availability under our senior secured credit facility will also be available if necessary. Capitalized interest and general and administrative expenses are included in the $80 million.
Capital expenditure plans for 2005 include:

- the completion and development of two 2004 shelf discoveries;
- the non-discretionary drilling of approximately 13 deep shelf and onshore exploratory wells we developed using our 3-D seismic and AVO technology;
- drilling of a development well on our deepwater Entrada discovery;
- drilling of two deepwater Medusa satellite prospects and one deepwater exploratory well;
- lease and seismic acquisition; and
- capitalized interest and overhead.

The following table describes our outstanding contractual obligations (in thousands) as of December 31, 2004:

Contractual Obligations	Total	Less Than One Year	One-Three Years	Four-Five Years	After-Five Years
Senior Secured Credit Facility	$ 5,000	$ —	$ 5,000	$ —	$ —
9.75% Senior Notes	200,000	—	—	—	200,000
Capital lease (future minimum payments)	2,531	822	787	457	465
Throughput Commitments:					
Medusa Spar, LLC	17,508	4,824	6,988	5,696	—
Medusa Oil Pipeline	860	254	311	132	163

Hurricane Ivan

On September 13, 2004, several of our fields were shut-in due to Hurricane Ivan. Two of our major fields, Medusa which is located in Mississippi Canyon Blocks 538 and 582 and Mobile Bay Blocks 952, 953 and 955, incurred damage as a result of the hurricane.

The Medusa spar production facility incurred minor damage, but a platform work-over rig owned by a third party incurred significant damage and had to be removed from the Medusa spar production facility. After debris clean up and repairs, partial production was restored on October 13, 2004 and pre-hurricane production levels were achieved by October 22, 2004.

Mobile Bay Blocks 952, 953 and 955 incurred minor damage and wells were brought on-line as repairs were completed. Partial production was restored on September 24, 2004 and the field reached pre-hurricane production levels by October 17, 2004.

Production from Medusa and Mobile Bay Blocks 952, 953 and 955 represented approximately 60% of our production for the eight months ended August 31, 2004.

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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, 2004.

	December 31,		
	2004	2003	2002(b)
Production:			
Oil (MBbls)	1,736	268	226
Gas (MMcf)	11,387	12,315	14,215
Total production (MMcfe)	21,801	13,923	15,571
Average daily production (MMcfe)	59.6	38.1	42.7
Average sales price (a):			
Oil (per Bbl)	$ 28.71	$ 28.72	$ 23.11
Gas (per Mcf)	$ 6.15	$ 5.36	$ 3.94
Total (per Mcfe)	$ 5.50	$ 5.29	$ 3.93
Oil and Gas revenues (in thousands):			
Gas revenue	$ 69,976	$66,001	$55,949
Oil revenue	49,826	7,696	5,222
Total	$119,802	$73,697	$61,171
Oil and gas production costs (in thousands):			
Lease operating expenses	$ 22,308	$11,301	$11,030
Additional per Mcfe data:			
Sales price	$ 5.50	$ 5.29	$ 3.93
Lease operating expenses	1.02	.81	.71
Operating margin	$ 4.48	$ 4.48	$ 3.22
Depletion	$ 2.18	$ 2.03	$ 1.73
Accretion	$ .16	$ .21	$ —
General and administrative (net of management fees)	$ .40	$ .34	$ .30

(a) Average sales price includes hedging gains and losses.

(b) Production volumes include 1,200 MMcf for the year 2002 at an average price of $2.08 per Mcf associated with a volumetric production payment.

Off-Balance Sheet Arrangements

In December 2003, we announced the formation of a limited liability company, Medusa Spar LLC, which now owns a 75% undivided ownership interest in the deepwater spar production facilities on our Medusa Field in the Gulf of Mexico. We contributed a 15% undivided ownership interest in the production facility to Medusa Spar LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC will earn a tariff based upon production volume throughput from the Medusa area. We are obligated to process our share of production from the Medusa Field and any future discoveries in the area through the spar production facilities. This arrangement allows us to defer the cost of the spar production facility over the life of the Medusa Field. Our cash proceeds were used to reduce the balance outstanding under our senior secured credit facility. The LLC used the cash proceeds from $83.7 million of non-recourse financing and a cash contribution by one of the LLC owners to acquire its 75% interest in the spar. On December 31, 2004, $64.1 million of the financing was outstanding. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. (NYSE:OII) and Murphy Oil Corporation (NYSE:MUR). We are accounting for our 10% ownership interest in the LLC under the equity method.

Comparison of Results of Operations for the Years Ended December 31, 2004 and 2003

Oil and Gas Revenues

Total production for 2004 increased by 57% versus 2003 and total oil and gas revenues increased 63% from $73.7 million in 2003 to $119.8 million in 2004. Increased production was primarily due to our deepwater discoveries, Medusa and Habanero, which began producing late in the fourth quarter of 2003.

Gas production during 2004 totaled 11.4 Bcf and generated $70.0 million in revenues compared to 12.3 Bcf and $66.0 million in revenues during the same period in 2003. Average gas prices realized for 2004 were $6.15 per Mcf compared to $5.36 per Mcf during the same period last year. The decrease in production was primarily due to downtime for Hurricane Ivan and the normal and expected decline in production from our Mobile area fields and older properties. These factors were partially offset by production from Medusa and Habanero.

Oil production during 2004 totaled 1,736,000 barrels and generated $49.8 million in revenues compared to 268,000 barrels and $7.7 million in revenues for the same period in 2003. Average oil prices realized in 2004 were $28.71 per barrel compared to $28.72 per barrel in 2003. The increase in production was due to the initial production from our deepwater discoveries, Medusa and Habanero, which began producing late in the fourth quarter of 2003. The production increase was offset slightly by downtime for Hurricane Ivan and normal and expected declines in production from older properties.

Lease Operating Expenses

Lease operating expenses for 2004 increased by 97% to $22.3 million compared to $11.3 million for the same period in 2003. The increase was primarily due to lease operating expenses related to our deepwater discoveries, Medusa and Habanero, which began producing late in the fourth quarter of 2003.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for 2004 and 2003 were $47.5 million and $28.3 million, respectively. The 68% increase was primarily due to higher production volumes for 2004 compared to 2003.

Accretion Expense

Accretion expense for 2004 and 2003 of $3.4 million and $2.9 million, respectively, represents accretion for our asset retirement obligations. The increase was due to the addition of plugging and abandonment obligations. See Note 8 to the Consolidated Financial Statements.

General and Administrative

General and administrative expenses for 2004, net of amounts capitalized, were $8.8 million compared to $4.7 million incurred in 2003. There was a charge in general and administrative expenses of $2.6 million in the first quarter of 2004 for the early retirement of two executive officers of the Company. Also reduced capitalized overhead, higher directors' fees, and increased independent and internal audit costs resulting from implementation of Sarbanes – Oxley 404 contributed to the increase in general and administrative expenses.

Interest Expense

Interest expense decreased by 34% in 2004 to $20.1 million compared to $30.6 million in 2003. This is a result of lower debt levels and lower interest rates due to the restructuring of debt in December 2003 and during the six-month period ended June 30, 2004 in additional to an equity offering completed in the second quarter of 2004. In addition, amortization of deferred financing costs and bond discounts decreased due to the write-off of unamortized deferred financing costs and bond discounts associated with the early extinguishment of debt.

Loss on Early Extinguishment of Debt

A loss of $3.0 million and $5.6 million was incurred in 2004 and 2003, respectively. Both were incurred for the write-off of deferred financing costs, pre-payment premiums and bond discounts associated with the early extinguishment of debt.

Income Taxes

The income tax benefit of $6.7 million in 2004 resulted primarily from the reversal of the valuation allowance established in 2003 against our deferred tax asset. As a result of production from our first two deepwater projects starting in November 2003, as well as refinancing its highest cost debt in 2004, we achieved profitable operations and have income on an aggregate basis for the three-year period ended December 31, 2004. Callon also expects 2005 production levels to exceed 2004 levels and expects to utilize most if not all of the deferred tax asset in 2005. As a result, we reversed the valuation allowance. See Note 3 to our Consolidated Financial Statements for a more detailed discussion.

Comparison of Results of Operations for the Years Ended December 31, 2003 and 2002

Oil and Gas Revenues

Total oil and gas revenues increased 20% from $61.2 million in 2002 to $73.7 million in 2003 while total production for 2003 decreased by 11% versus 2002. Realized oil and gas prices were substantially higher when compared to the same period in 2002 and accounted for the increase in revenue. Gas revenues for 2002 included $9.2 million of non-cash revenue related to the Enron derivatives discussed in Note 6 to the Consolidated Financial Statements.

Gas production during 2003 totaled 12.3 Bcf and generated $66.0 million in revenues compared to 14.2 Bcf and $55.9 million in revenues during the same period in 2002. Average gas prices for 2003 were $5.36 per Mcf compared to $3.94 per Mcf during the same period in 2002. The decrease in production was primarily due to the depletion of the lowest productive zone of the East Cameron Block 294 field. The well at East Cameron Block 294 was returned to production after a recompletion to a behind pipe zone in the third quarter of 2003. Also, the sale of the North and Northwest Dauphin Island fields in the fourth quarter of 2002 and the normal and expected declines in production from other properties contributed to the variance.

Oil production during 2003 totaled 268,000 barrels and generated $7.7 million in revenues compared to 226,000 barrels and $5.2 million in revenues for the same period in 2002. Average oil prices received in 2003 were $28.72 per barrel compared to $23.11 per barrel in 2002. The increase in production was due to the initial production from our deepwater discoveries, Medusa and Habanero, which began producing late in the fourth quarter of 2003. This was offset slightly by downtime for maintenance to the facility and equipment at the Big Escambia Creek Field formally operated by ExxonMobil Corporation, currently operated by Vintage, and normal and expected declines in production from older properties.

Lease Operating Expenses

Lease operating expenses for 2003 increased by 2% to $11.3 million compared to $11.0 million for the same period in 2002. The increase was primarily due to the increase in lease operating expenses for the Mobile Block 864 area resulting from the implementation of the accelerated production program in the second quarter of 2002 and lease operating expenses related to our deepwater discoveries, Medusa and Habanero, which began producing late in the fourth quarter of 2003. The increase was slightly offset as a result of the sale of North and Northwest Dauphin Island fields in the fourth quarter of 2002 which reduced lease operating expenses for 2003.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for 2003 and 2002 were $28.3 million and $27.1 million, respectively. The 4% increase was due primarily to the downward reserve revisions for our Boomslang Field at Ewing Bank Block 994 at the end of 2002. This decrease in estimated proved reserves increased the depletable cost per unit of production.

Accretion Expense

Accretion expense of $2.9 million represents accretion for our asset retirement obligations for 2003.

General and Administrative

General and administrative expenses for 2003, net of amounts capitalized, were $4.7 million and flat with the amount incurred in 2002.

Interest Expense

Interest expense increased by 17% in 2003 to $30.6 million compared to $26.1 million in 2002. This was a result of higher debt levels.

Loss on Early Extinguishment of Debt

A loss of $5.6 million was incurred in December of 2003 for the write-off of deferred financing costs and bond discounts associated with the early extinguishment of $85 million of the 12% loans due in 2005 plus a 1% pre-payment premium.

Income Taxes

The income tax expense of $8.4 million in 2003 was primarily due to a charge of $11.5 million to establish a valuation allowance against our deferred tax asset. We incurred losses in 2002 and 2003 and had losses on an aggregate basis for the three-year period ended December 31, 2003. Because of these cumulative losses we established a full valuation allowance. See Note 3 to our Consolidated Financial Statements for a more detailed discussion.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

The Company’s revenues are derived from the sale of its crude oil and natural gas production. In recent months, the prices for oil and gas have increased; however, they remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supplies, weather conditions, economic conditions and government actions. The Company enters into derivative financial instruments to hedge oil and gas price risks for the production volumes to which the hedge relates. The derivatives reduce the Company’s exposure on the hedged volumes to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices on the hedged volumes.

The Company also enters into price “collars” to reduce the risk of changes in oil and gas prices. Under these arrangements, no payments are due by either party so long as the market price is above the floor price set in the collar and below the ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to the Company and if the price is above the ceiling, the counter-party receives the difference from the Company. Another type of hedging contract Callon has entered into is a put contract. Under a put, if the price falls below the set floor price, the counter-party to the contract pays the difference to the Company. The Company enters into these various agreements to reduce the effects of volatile oil and gas prices and does not enter into hedge transactions for speculative purposes. See Note 6 to the Consolidated Financial Statements for a description of the Company’s hedged position at December 31, 2004. There have been no significant changes in market risks faced by the Company since the end of 2004.

Based on projected annual sales volumes for 2005 (excluding forecast production increases over 2004), a 10% decline in the prices Callon receives for its crude oil and natural gas production would have an approximate $13.3 million impact on our revenues.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

The Stockholders and Board of Directors
Callon Petroleum Company

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2004. 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 the standards of the Public Company Accounting Oversight Board (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 consolidated financial position of Callon Petroleum Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations".

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Callon Petroleum Company's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 8, 2005, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 8, 2005

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

	December 31, 2004	December 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,266	$ 8,700
Restricted cash	—	63,345
Accounts receivable	14,928	10,117
Deferred tax asset-current	5,676	—
Restricted investments-current	2,055	—
Fair market value of derivatives	1,570	—
Other current assets	581	3,606
Total current assets	28,076	85,768
Oil and gas properties, full-cost accounting method:		
Evaluated properties	862,101	802,912
Less accumulated depreciation, depletion and amortization	(494,453)	(447,000)
	367,648	355,912
Unevaluated properties excluded from amortization	39,042	34,251
Total oil and gas properties	406,690	390,163
Other property and equipment, net	1,541	1,547
Deferred tax asset	2,986	—
Long-term gas balancing receivable	725	1,101
Restricted investments	5,687	7,420
Investment in Medusa Spar LLC	9,787	8,471
Other assets, net	2,031	1,562
Total assets	$ 457,523	$ 496,032
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 15,728	$ 15,855
Fair market value of derivatives	2,993	165
Undistributed oil and gas revenues	1,162	897
Accrued net profits interest payable	1,927	1,886
Suspended Medusa oil royalties	5,430	—
Asset retirement obligations-current	13,300	8,571
Current maturities of long-term debt	576	93,223
Total current liabilities	41,116	120,597
Long-term debt	192,351	214,885
Asset retirement obligations	24,982	25,120
Other long-term liabilities	762	2,169
Total liabilities	259,211	362,771
Stockholders' equity:		
Preferred Stock, $.01 par value; 2,500,000 shares authorized; 596,671 shares of Convertible Exchangeable Preferred Stock, Series A issued and outstanding at December 31, 2004 with a liquidation preference of $14,916,775	6	6
Common Stock, $.01 par value; 30,000,000 shares authorized; 17,616,596 shares and 13,935,311 shares outstanding at December 31, 2004 and 2003, respectively	176	139
Unearned compensation-restricted stock	(5,352)	(372)
Capital in excess of par value	220,664	169,036
Other comprehensive loss	(1,883)	(20)
Retained earnings (deficit)	(15,299)	(35,528)
Total stockholders' equity	198,312	133,261
Total liabilities and stockholders' equity	$ 457,523	$ 496,032

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

Callon Petroleum Company
Consolidated Statements of Operations
For the Years Ended December 31, 2004, 2003 and 2002
(In thousands, except per share amounts)

	2004	2003	2002
Operating revenues:			
Oil and gas sales	$119,802	$ 73,697	$61,171
Operating expenses:			
Lease operating expenses	22,308	11,301	11,030
Depreciation, depletion and amortization	47,453	28,253	27,096
General and administrative	8,758	4,713	4,705
Accretion expense	3,400	2,884	—
Derivative expense	1,371	535	708
Total operating expenses	83,290	47,686	43,539
Income from operations	36,512	26,011	17,632
Other (income) expenses:			
Interest expense	20,137	30,614	26,140
Other (income)	(357)	(444)	(1,004)
Loss on early extinguishment of debt	3,004	5,573	—
Gain on sale of pipeline	—	—	(2,454)
Gain on sale of Enron derivatives	—	—	(2,479)
Total other (income) expenses	22,784	35,743	20,203
Income (loss) before income taxes	13,728	(9,732)	(2,571)
Income tax expense (benefit)	(6,697)	8,432	(900)
Income (loss) before Medusa Spar LLC and cumulative effect of change in accounting principle	20,425	(18,164)	(1,671)
Income (loss) on Medusa Spar LLC, net of tax	1,076	(8)	—
Income (loss) before cumulative effect of change in accounting principle	21,501	(18,172)	(1,671)
Cumulative effect of change in accounting principle, net of tax	—	181	—
Net income (loss)	21,501	(17,991)	(1,671)
Preferred stock dividends	1,272	1,277	1,277
Net income (loss) available to common shares	$ 20,229	$(19,268)	$ (2,948)
Net income (loss) per common share:			
Basic			
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.28	$ (1.42)	$ (0.22)
Cumulative effect of change in accounting principle, net of tax	—	0.01	—
Net income (loss) available to common	$ 1.28	$ (1.41)	$ (0.22)
Diluted			
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.22	$ (1.42)	$ (0.22)
Cumulative effect of change in accounting principle, net of tax	—	0.01	—
Net income (loss) available to common	$ 1.22	$ (1.41)	$ (0.22)
Shares used in computing net income (loss):			
Basic	15,796	13,662	13,387
Diluted	17,678	13,662	13,387

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	Unearned Restricted Stock Compensation	Capital in Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Stock-holders' Equity
Balances, December 31, 2001	$ 6	$ 134	$ —	$154,425	$ 5,971	$(13,312)	$147,224
Comprehensive income (loss):							
Net loss	—	—	—	—	—	(1,671)	
Other comprehensive loss	—	—	—	—	(6,440)	—	
Total comprehensive loss							(8,111)
Preferred stock dividends	—	—	—	—	—	(1,277)	(1,277)
Shares issued pursuant to employee benefit and option plan	—	1	—	770	—	—	771
Employee stock purchase plan	—	—	—	79	—	—	79
Tax benefits related to stock compensation plans	—	—	—	(29)	—	—	(29)
Restricted stock	—	3	(826)	1,849	—	—	1,026
Warrants	—	1	—	1,276	—	—	1,277
Balances, December 31, 2002	6	139	(826)	158,370	(469)	(16,260)	140,960
Comprehensive income (loss):							
Net loss	—	—	—	—	—	(17,991)	
Other comprehensive income	—	—	—	—	449	—	
Total comprehensive loss							(17,542)
Preferred stock dividends	—	—	—	—	—	(1,277)	(1,277)
Shares issued pursuant to employee benefit and option plan	—	1	—	427	—	—	428
Employee stock purchase plan	—	—	—	127	—	—	127
Restricted stock	—	(1)	454	(516)	—	—	(63)
Warrants	—	—	—	10,628	—	—	10,628
Balances, December 31, 2003	6	139	(372)	169,036	(20)	(35,528)	133,261
Comprehensive income (loss):							
Net income	—	—	—	—	—	21,501	
Other comprehensive (loss)	—	—	—	—	(1,863)	—	
Total comprehensive income							19,638
Preferred stock dividend	—	—	—	—	—	(1,272)	(1,272)
Sale of common stock	—	35	—	44,012	—	—	44,047
Shares issued pursuant to employee benefit and option plan	—	1	—	720	—	—	721
Employee stock purchase plan	—	1	—	208	—	—	209
Tax benefits related to stock compensation plans	—	—	—	1,214	—	—	1,214
Restricted stock	—	—	(4,980)	5,474	—	—	494
Balances, December 31, 2004	$ 6	$ 176	$ (5,352)	$220,664	$ (1,883)	$(15,299)	$198,312

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003 and 2002
(In thousands)

	2004	2003	2002
Cash flows from operating activities:			
Net income (loss)	$ 21,501	$ (17,991)	$ (1,671)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	48,164	29,264	27,774
Accretion expense	3,400	2,884	—
Amortization of deferred financing costs	1,929	6,568	5,521
Non-cash loss on extinguishment of debt	2,910	4,423	
Amortization of deferred production payment revenue	—	—	(2,406)
Income from investment in Medusa Spar, LLC	(1,076)	—	—
Cumulative effect of change in accounting principle	—	(181)	—
Non-cash derivative income	—	—	(9,186)
Non-cash derivative expense	(135)	487	708
Deferred income tax expense (benefit)	(6,697)	8,432	(900)
Gain on sale of pipeline	—	—	(2,454)
Non-cash charge related to compensation plans	1,225	858	1,267
Changes in current assets and liabilities:			
Accounts receivable, trade	(4,495)	(1,438)	(4,967)
Other current assets	971	(2,667)	(104)
Current liabilities	2,903	5,185	3,198
Investment in derivative contracts	—	—	(1,687)
Change in gas balancing receivable	376	(340)	(288)
Change in gas balancing payable	400	(491)	(390)
Change in other long-term liabilities	(20)	(15)	67
Change in other assets, net	(448)	(349)	(2,315)
Cash provided (used) by operating activities	70,908	34,629	12,167
Cash flows from investing activities:			
Capital expenditures	(64,649)	(50,705)	(66,023)
Distribution from Medusa Spar, LLC	339	24,908	—
Proceeds from sale of pipeline and other facilities	—	1,500	6,784
Proceeds from sale of mineral interests	—	982	4,492
Cash provided (used) by investing activities	(64,310)	(23,315)	(54,747)
Cash flows from financing activities:			
Change in accounts payable and accrued liability to be refinanced	—	(3,861)	(5,697)
Increase in debt	90,000	198,000	109,900
Payments on debt	(205,915)	(133,000)	(58,085)
Restricted cash	63,345	(63,345)	—
Debt issuance cost	(984)	(3,745)	(2,291)
Issuance of common stock	44,047	—	—
Equity issued related to employee stock plans	199	127	79
Capital leases	(1,452)	(1,320)	(1,129)
Cash dividends on preferred stock	(1,272)	(1,277)	(1,277)
Cash provided (used) by financing activities	(12,032)	(8,421)	41,500
Net increase (decrease) in cash and cash equivalents	(5,434)	2,893	(1,080)
Cash and short-term investments:			
Balance, beginning of period	8,700	5,807	6,887
Balance, end of period	$ 3,266	$ 8,700	$ 5,807

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" or "Callon") 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 ("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 and offshore Gulf of Mexico.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Reporting

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

Use of Estimates

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

Accounting Pronouncements

On December 16, 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004), ("SFAS 123R") Share-Based Payment, which is a revision of Statement of Financial Accounting Standards No. 123, ("SFAS 123") *Accounting for Stock-Based Compensation.* SFAS 123R supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and amends Statement of Financial Accounting Standards No. 95, *Statement of Cash Flows.* Generally, the approach in SFAS 123R is similar to the approach described in SFAS 123. However, SFAS 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro forma disclosure is no longer an alternative.

SFAS 123R must be adopted no later than July 1, 2005. Early adoption will be permitted in periods in which financial statements have not yet been issued. SFAS 123R permits public companies to adopt its requirements using one of two methods below:

- A "modified prospective" method in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS 123R for all share-based payments granted after the effective date and (b) based on the requirements of SFAS 123 for all awards granted to employees prior to the effective date of SFAS 123R that remain unvested on the effective date; or

- A "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

The Company expects to adopt SFAS 123R on July 1, 2005 using the modified prospective method.

As permitted by SFAS 123, the Company currently accounts for share-based payments to employees using Opinion 25's intrinsic value method and, as such, generally recognizes no compensation cost for employee stock options. Accordingly, the adoption of SFAS 123R's fair value method will have a significant impact on our result of operations, although it will have no impact on our overall financial position. The impact of adoption of SFAS 123R cannot be predicted at this time because it will depend on levels of share-based payments granted in the future. However, had we adopted SFAS 123R in prior periods, the impact of that standard would have approximated the impact of SFAS 123 as described in the disclosure of pro forma net income and earnings per share below under Stock-Based Compensation.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin (ARB) 51" ("FIN 46"). FIN 46 addresses consolidation by business enterprises of variable interest entities ("VIEs"). The primary objective of FIN 46 is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. The Company adopted FIN 46, as revised, as of December 31, 2003, which had no impact on the Company's results of operations or financial position.

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") No. 106 which expressed the Staff's views regarding the application of Statement of Financial Accounting Standards ("SFAS") No. 143 "Accounting for Asset Retirement Obligations" by oil and gas producing companies following the full-cost accounting method. SAB No. 106 specifies that subsequent to the adoption of SFAS No. 143 an oil and gas company following the full-cost method of accounting should include assets recorded in connection with the recognition of an asset retirement obligation pursuant to SFAS No. 143 as part of the costs subject to the full-cost ceiling limitation. The future cash outflows associated with settling the recorded asset retirement obligations should be excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test. The Company will be required to adopt the provisions of SAB No. 106 prospectively in the first quarter of 2005 which will have no impact on the Company's results of operation or financial position.

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. 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 ($7.2 million in 2004, $8.4 million in 2003 and $9.6 million in 2002) do not include any costs related to production or general corporate overhead. Costs associated with unevaluated properties, including capitalized interest on such costs, 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 that these costs have been impaired.

Costs of properties, including future development and future site restoration, dismantlement and abandonment costs, which have proved reserves and properties 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 accumulated amortization and deferred taxes relating to oil and gas properties, 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 9.

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 available geological, engineering and regulatory data. 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. Until January 1, 2003, such costs were capitalized as oil and gas properties as the actual restoration, dismantlement and abandonment activities took place. As discussed below under Asset Retirement Obligations, beginning January 1, 2003, the Company changed the method for which we account for such costs upon adoption of SFAS 143 and these costs are now included in the full cost pool. For purposes of the full-cost ceiling test, the Company nets the Asset Retirement Obligation liability against the net capitalized costs of oil and gas properties and includes the future cash outflows associated with asset retirement obligations in the valuation of the full-cost ceiling amount.

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. Depreciation expense of $346,000, $578,000 and $696,000 relating to other property and equipment was included in general and administrative expenses in the Company’s statements of operations for the years ended December 31, 2004, 2003 and 2002, respectively. The accumulated depreciation on other property and equipment was $10.4 million and $10.2 million as of December 31, 2004 and 2003, respectively.

Investment in Medusa Spar LLC

In December 2003, the Company announced the formation of a limited liability company, Medusa Spar LLC, which now owns a 75% undivided ownership interest in the deepwater spar production facilities on Callon’s Medusa Field in the Gulf of Mexico. The Company contributed a 15% undivided ownership interest in the production facility to Medusa Spar LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC will earn a tariff based upon production volume throughput from the Medusa area. Callon is obligated to process our share of production from the Medusa

Field and any future discoveries in the area through the spar production facilities. This arrangement allows Callon to defer the cost of the spar production facility over the life of the Medusa Field. The Company's cash proceeds were used to reduce the balance outstanding under its senior secured credit facility. The LLC used the cash proceeds from $83.7 million of non-recourse financing and a cash contribution by one of the LLC owners to acquire its 75% interest in the spar. On December 31, 2004, $64.1 million of the financing was outstanding. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. (NYSE:OII) and Murphy Oil Corporation (NYSE:MUR). The Company is accounting for our 10% ownership interest in the LLC under the equity method.

Asset Retirement Obligations

In June 2001, the FASB issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations ("SFAS 143") effective for fiscal years beginning after June 15, 2002. SFAS 143 essentially requires entities to record the fair value of a liability for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Callon adopted SFAS 143 on January 1, 2003 resulting in a cumulative effect of accounting change of $181,000, net of tax. See Note 8.

Natural Gas Imbalances

The Company follows the 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. Gas balancing receivables were $725,000 and $1.1 million as of December 31, 2004 and 2003, respectively. Gas balancing payables were $594,000 and $193,000 as of December 31, 2004 and 2003, respectively.

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 are accounted for under SFAS 133. See Note 6

Income Tax

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. See Note 3.

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 $103,000 at December 31, 2004 and 2003. Net charge offs recorded against the reserve for doubtful accounts were $40,000 in 2003. There were no provisions to expense in the three-year period ended December 31, 2004.

Accounts Payable and Accrued Liabilities to be Refinanced

Amounts included in the Consolidated Balance Sheet represent capital expenditures in accounts payable and accrued liabilities that were refinanced with the availability under the Company's senior secured credit facility subsequent to a specific Balance Sheet date. As of December 31, 2004, there were no capital expenditures to be refinanced in the following month. Amounts in 2003 were classified as short term because of the maturity of the credit facility on June 30, 2004.

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 deferred revenue associated with the sale of this production payment interest because a substantial obligation for future performance existed. Under the terms of the sale, the Company was obligated to deliver the production volumes free and clear of royalties, lease operating expenses, production taxes and all capital costs. The production payment was amortized, beginning in June 1999, to oil and gas sales on the units-of-production method as associated hydrocarbons were delivered, and expired in July 2002.

Stock-Based Compensation

The Company's pro forma net income (loss) and net income (loss) per share of common stock for the 12-month periods ended December 31, 2004, 2003 and 2002 had compensation costs been recorded using the fair value method in accordance with SFAS 123, as amended by SFAS 148, are presented below pursuant to the disclosure requirements of SFAS 148 (in thousands except per share data):

		2004	2003	2002
		(In thousands, except per share data)		
Net income (loss) available to common shares, as reported		$ 20,229	$ (19,268)	$ (2,948)
Stock-based compensation expense included in net income as reported, net of tax		348	17	270
Deduct: Total stock-based compensation expense under fair value based method, net of tax		(549)	(247)	(907)
Pro forma net income (loss) available to common shares		$ 20,028	$ (19,498)	$ (3,585)
Basic earnings (loss) per share:	As Reported	1.28	(1.41)	(.22)
	Pro Forma	1.27	(1.43)	(.27)
Diluted earnings (loss) per share:	As Reported	1.22	(1.41)	(.22)
	Pro Forma	1.20	(1.43)	(.27)

See Note 12 for descriptions and additional disclosures related to the plans.

Major Customers

The Company's production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom it sold a significant percentage of its total oil and gas production during each of the 12-month periods ended:

	December 31,		
	2004	2003	2002
Petrocom Energy Group, Ltd.	—	4%	4%
Dynegy	—	5%	7%
Prior Energy Corporation	—	20%	—
Reliant Energy Services	6%	28%	70%
Louis Dreyfus Energy Services	23%	27%	—
Shell Trading Company	30%	—	—
Plains Marketing, L.P.	13%	—	—
Conoco Phillips Company	8%	—	—
Chevron Texaco Natural Gas	6%	—	—

Because alternative purchasers of oil and gas are readily available, the Company believes that the loss of any of these purchasers would not result in a material adverse effect on its 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.

The Company paid no federal income taxes for the three years in the period ended December 31, 2004. During the years ended December 31, 2004, 2003 and 2002, the Company made cash payments for interest of $23,197,000, $27,913,000 and $25,507,000, respectively.

Per Share Amounts

Basic income or loss per common share was 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 and the effect of the convertible preferred stock (if dilutive). The conversion of the preferred stock was not included in the annual calculation for 2003 and 2002 due to its antidilutive effect on diluted income or loss per common share. In addition, below are the shares relating to stock options, warrants and restricted stock that were not included in diluted shares for the twelve-month periods ended December 31, 2003 and 2002 due to the fact that the Company had a loss for these periods. The Company had net income for the period ended December 31, 2004 and all such shares were included as described below.

	Twelve Months Ended December 31, (in thousands)	
	2003	2002
Stock options	63	13
Warrants	424	372
Restricted Stock	248	122

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

	2004	2003	2002
(a) Net income (loss) available to common shares	$ 20,229	$(19,268)	$ (2,948)
Preferred dividends assuming conversion of preferred stock (if dilutive)	1,272	—	—
(b) Income (loss) available to common shares assuming conversion of preferred stock (if dilutive)	$ 21,501	$(19,268)	$ (2,948)
(c) Weighted average shares outstanding	15,796	13,662	13,387
Dilutive impact of stock options	233	—	—
Dilutive impact of restricted stock	75	—	—
Dilutive impact of warrants	894	—	—
Convertible preferred stock (if dilutive)	680	—	—
(d) Total diluted shares	17,678	13,662	13,387
Stock options and warrants excluded due to the exercise price being greater than the stock price	89	2,297	2,250
Basic income (loss) per share (a¸c)	$ 1.28	$ (1.41)	$ (.22)
Diluted income (loss) per share (b¸d)	$ 1.22	$ (1.41)	$ (.22)

Fair Value of Financial Instruments

Fair value of cash, cash equivalents, accounts receivable, accounts payable, the capital lease and the senior secured credit facility approximates book value at December 31, 2004 and 2003. Fair value of long-term debt (specifically, the 9.75% Senior Notes) had an estimated fair value of 106% of face value at December 31, 2004. Fair value of long-term debt (specifically, the 10.125%, the 10.25%, and the 11% Senior Subordinated Notes and the 12% loans) had an estimated fair value of 100% of face value at December 31, 2003.

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3. INCOME TAXES

The Company has recorded a net deferred tax asset at December 31, 2004 and 2003 and a valuation allowance at December 31, 2003 as follows:

	December 31, 2004	December 31, 2003
	(In thousands)	
Federal net operating loss carryforwards	$ 56,271	$ 61,805
Statutory depletion carryforward	4,124	4,255
Alternative minimum tax credit carryforward	326	—
Temporary differences:		
Oil and gas properties	(66,200)	(66,725)
Pipeline and other facilities	—	—
Non-oil and gas property	(77)	(16)
Other	1,988	2,031
SFAS 143-Asset Retirement Obligations	11,544	10,563
Permanent differences:		
Employee benefits	787	(428)
Other	(101)	17
Total tax asset	8,662	11,502
Valuation allowance	—	(11,502)
Net tax asset	$ 8,662	$ —

SFAS 109 provides for the weighing of positive and negative evidence in determining whether it is more likely than not that a deferred tax asset is recoverable. The Company incurred losses in 2002 and 2003 and had losses on an aggregate basis for the three-year period ended December 31, 2003. Because of these cumulative losses the Company established a full valuation allowance of $11.5 million as of December 31, 2003.

As a result of production from the Company's first two deepwater projects starting in November 2003, as well as refinancing its highest cost debt in 2004, the Company achieved profitable operations and has income on an aggregate basis for the three-year period ended December 31, 2004. Callon also expects 2005 production levels to exceed 2004 levels and expects to utilize most if not all of the deferred tax asset in 2005. As a result, the Company reversed the valuation allowance which had a balance of $7.0 million as of December 31, 2004.

Below is a reconciliation of the reported amount of income tax expense attributable to continuing operations for the year to the amount of income tax expense that would result from applying domestic federal statutory tax rates to pretax income from continuing operations.

	Year Ended December 31,		
	2004	2003	2002
Income tax expense (benefit) computed at the statutory federal income tax rate	35%	(35%)	(35%)
Change in valuation allowance	(84%)	118%	—
Write off of NOL's	—	4%	—
Effective income tax rate	(49%)	87%	(35%)

If not utilized, the Company's federal net operating loss carryforwards will expire in 2013 through 2018. 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.

4. OTHER COMPREHENSIVE INCOME

A recap of the Company's 2004, 2003 and 2002 other comprehensive income (net of tax of $1.0 million, $242,000, and $3.5 million, respectively) is shown below (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Other comprehensive income (loss):			
Change in fair value of derivatives	$ (1,863)	$ 449	$ (469)
Amortization of Enron derivatives	—	—	(5,971)
Total other comprehensive income (loss)	$ (1,863)	$ 449	$ (6,440)

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

	December 31, 2004	December 31, 2003
	(In thousands)	
Senior Secured Credit Facility	$ 5,000	$ 30,000
Senior Subordinated Notes (due 2004) – ***these notes were retired with restricted cash on 01/08/2004:***		
10.125% notes net of discount	—	21,772*
10.250% notes	—	40,000*
12% Senior Loans (due 2005) net of discount	—	9,490
11% Senior Subordinated Notes (due 2005)	—	33,000
9.75% Senior Notes (due 2010) net of discount	186,216	170,684
Capital Lease	1,711	3,162
Total Long-term Debt	192,927	308,108
Less current portion	576	93,223*
Long-term portion	$192,351	$214,885

* $62.9 million of 2004 senior subordinated notes are in this current portion and were retired on January 8, 2004.

Senior Secured Credit Facility. On June 15, 2004, the Company closed on a three-year senior secured credit facility underwritten by Union Bank of California, N.A. ("Union Bank") to replace the Company's credit facility with Wachovia Bank, National Association ("Wachovia Bank") which was expiring June 30, 2004. The credit facility includes an initial borrowing base of $60 million, which may be adjusted semi-annually and can be increased to a maximum of $175 million. Borrowings under the credit facility are secured by mortgages covering the Company's five largest fields. The credit facility bears interest at 0.25% above a defined base rate depending on utilization of the borrowing base or, at the option of the Company, LIBOR plus 1.5% to 2.25% based on utilization of the borrowing base. Under the senior secured 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 range of interest rates on the senior secured credit facilities for both Union Bank and Wachovia Bank combined were 3.09% to 5.50% for the 12 months ended December 31, 2004. The weighted average interest rate for the senior secured credit facilities debt outstanding at December 31, 2004 and 2003 was 4.16% and 15%, respectively.

As of December 31, 2004 there was $5.0 million outstanding under the facility and Callon had an aggregate of $2.3 million in outstanding letters of credit issued under the credit facility. These letters of credit secure obligations under the outstanding hedging contracts described in Note 6 to the Consolidated Financial Statements. The outstanding letters of credit reduce the amount available for borrowings under the credit facility. As a result, $52.7 million was available for future borrowings under the credit facility as of December 31, 2004.

Restructured Debt. In December 2003 and in the first half of 2004, the Company completed several transactions which restructured all debt that was maturing through 2005. The transactions were

- borrowing $185 million pursuant to a senior unsecured credit facility for a term of seven years at an interest rate of 9.75% in December 2003;
- the formation of Medusa Spar LLC in which the Company contributed its 15% ownership in the deepwater spar production facilities in return for a 10% interest in Medusa Spar LLC and approximately $25 million in cash;
- borrowing an additional $15 million for a term of seven years at an interest rate of 9.75% pursuant to a senior unsecured credit agreement in the first quarter of 2004;
- closing a three-year senior secured credit facility with an initial borrowing base of $60 million in June 2004 which can be increased by the lender to $175 million; and
- closing the public offering of 3,450,000 shares of common stock priced at $13.25 per share raising net proceeds of approximately $44 million, after expenses, in June 2004.

Below is a list of the debt which was extinguished and restructured with the funds raised from the transactions above.

- the Company's $22.9 million, 10.125% senior subordinated notes due in 2004
- the Company's $40 million, 10.25% senior subordinated notes due in 2004
- the Company's $95 million, 12% senior unsecured credit facility due in 2005
- the Company's $33 million, 11% senior subordinated notes due in 2005

All of the above debt was extinguished before maturity which resulted in a loss on early extinguishment of debt for the twelve-month periods ended December 31, 2004 and 2003 of $3.0 million and $5.6 million, respectively. In addition to restructuring the Company's debt, Callon reduced the balance outstanding on its senior secured credit facility.

9.75% Senior Notes (due 2010). In December 2003 the Company borrowed $185 million pursuant to a senior unsecured credit facility. The loans under the credit facility have a stated interest rate of 9.75% and a seven-year maturity. The net proceeds of $181.3 million were used to redeem $22.9 million of 10.125% senior subordinated notes due July 31, 2004, $40 million of 10.25% senior subordinated notes due September 15, 2004 and $85 million of our 12% loan due March 31, 2005 issued pursuant to a senior unsecured credit agreement dated July 29, 2001 plus a 1% pre-payment premium of $850,000, and to reduce the balance outstanding under the Company's senior secured credit facility. In conjunction with the new senior unsecured notes, the Company issued detachable warrants to purchase 2.775 million shares of it's common stock at an exercise price of $10 per share and an expiration date in December 2010. The warrants were valued at $10.6 million and were treated as a discount on the debt. This senior unsecured debt matures December 8, 2010 and has an effective interest rate of 11.4%. The Company recorded the issuance of these new securities at a fair value of $171 million. Deferred costs of $14 million associated with the notes will be amortized over the life of the notes.

During March 2004, Callon borrowed an additional $15 million under its 9.75% senior unsecured credit facility bringing the total outstanding under the facility to $200 million. The net proceeds of approximately $14 million were primarily used to retire the remaining $10 million of 12% senior loans due March 31, 2005 plus a 1% call premium of $100,000. The Company recorded the issuance of these additional new securities at a fair value of $14 million. Deferred costs of $1 million associated with the notes will be amortized over the life of the notes.

In March 2004, the $200 million in aggregate principal amount of loans outstanding under the 9.75% senior unsecured credit facility were exchanged for 9.75% Senior Notes due 2010, Series A, "Series A notes", issued pursuant to a senior indenture between Callon and American Stock Transfer & Trust Company dated March 15, 2004. On August 12, 2004, the Company completed an offer to exchange its 9.75% Senior Notes due 2010, Series B, that have been registered under the Securities Act of 1933, for all outstanding Series A notes.

Capital Lease. In December 2001, the Company entered into a 10-year gas processing agreement associated with a production facility on Callon's Mobile Block 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 obligations representing $5.6 million.

Restrictive Covenants. The senior secured credit facility and the 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 was in compliance with these covenants at December 31, 2004.

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

Year	Capital Lease Payments	Debt
2005	$ 822	$ —
2006	439	—
2007	348	5,000
2008	228	—
2009	229	—
Thereafter	465	200,000

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6. DERIVATIVES

The Company periodically uses derivative financial instruments to manage oil and gas price risk. Settlements 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.

The Company's derivative contracts that are accounted for as cash flow hedges under SFAS 133 are recorded at fair market value and the changes in fair value are recorded through other comprehensive income (loss), net of tax, in stockholders' equity. The cash settlements on these contracts are recorded as an increase or decrease in oil and gas sales. Cash settlements on the derivative contracts for the twelve-month periods ended December 31, 2004 and 2003 resulted in a reduction of oil and gas sales in the amount of $13.8 million and $2.9 million, respectively, and an increase in oil and gas sales of $9.2 million for the twelve-month period ended December 31, 2002.

The changes in fair value of the Company's derivative contracts that are not designated as effective cash flow hedges are recorded through the statement of operations as derivative expense. In addition, the change in fair value relating to the ineffective portion of cash flow hedges is recorded as derivative expense. The following table summarizes derivative expense for the periods presented (in thousands):

	December 31,		
	2004	2003	2002
Ineffective portion of hedges qualifying for hedge accounting included in derivative expense	$ (1,209)	$ —	$ —
Non-designated derivative contracts included in derivative expense	(162)	(535)	(708)
	$ (1,371)	$ (535)	$ (708)

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The fair value of all the oil and a portion of the gas derivative contracts at December 31, 2004 was a current liability of $2,993,000. The fair value of the remaining portion of the gas derivative contracts was a current asset of $1,570,000.

Listed in the table below are the outstanding derivative contracts as of December 31, 2004:

Swaps

Product	Volumes per Month	Quantity Type	Average Price	Period
Oil	30,000	Bbls	$ 31.29	01/05
Oil	15,000	Bbls	$ 30.00	01/05-03/05

Puts

Product	Volumes per Month	Quantity Type	Average Price	Period
Oil	50,000	Bbls	$ 35.00	02/05-06/05
Oil	7,000	Bbls	$ 35.00	01/05-12/05
Natural Gas	270,000	MMBtu	$ 5.00	04/05-10/05
Natural Gas	120,000	MMBtu	$ 5.00	01/05-10/05
Natural Gas	100,000	MMBtu	$ 5.00	04/05-12/05
Natural Gas	300,000	MMBtu	$ 6.50	01/05-03/05

Collars

Product	Volumes per Month	Quantity Type	Average Floor Price	Average Ceiling Price	Period
Oil	45,000	Bbls	$ 29.33	$ 32.17	01/05
Oil	15,000	Bbls	$ 32.50	$ 40.00	01/05-12/05
Oil	15,208	Bbls	$ 40.00	$ 50.00	01/05-12/05
Oil	15,000	Bbls	$ 32.50	$ 40.00	02/05-12/05
Oil	15,000	Bbls	$ 35.00	$ 43.50	03/05-12/05
Natural Gas	300,000	MMBtu	$ 5.00	$ 6.91	01/05-03/05
Natural Gas	190,000	MMBtu	$ 5.00	$ 12.80	01/05-03/05
Natural Gas	100,000	MMBtu	$ 5.00	$ 7.75	04/05-10/05
Natural Gas	200,000	MMBtu	$ 5.75	$ 7.75	04/05-10/05

7. COMMITMENTS AND CONTINGENCIES

As described in Note 11, 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, 2004, total estimated site restoration, dismantlement and abandonment costs were approximately $7.8 million, 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 Notes 2 and 8.

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 Medusa deepwater property is eligible for royalty suspensions pursuant to the Deep Water Royalty Relief Act. However, the federal offshore leases covering this property contains "price threshold" provisions for oil and gas prices. Under these "price threshold" provisions, if the average monthly New York Mercantile Exchange (NYMEX) sales price for oil or gas during a fiscal year exceeds the price threshold for oil or gas, respectively, then royalties on the associated production must be paid to the Minerals Management Service (MMS) at the rate stipulated in the lease. The price thresholds are adjusted annually by the implicit price deflator for the GDP. The determination of whether or not royalties are due as a result of the average NYMEX price exceeding the price threshold is made during the first quarter of the succeeding year. Any royalty payments due must be made shortly after this determination is made. If a royalty payment is due for all production during a year as a result of exceeding the price threshold, the lessee is required to make monthly royalty payments during the succeeding fiscal year for the succeeding year's production. If at the end of any year the average NYMEX price is below the price threshold, the lessee can apply for a refund for any associated royalties paid during that year and the lessee will not be required to pay royalties monthly during the succeeding year for the succeeding year's production.

The thresholds and the average NYMEX prices are calculated by the MMS. The average NYMEX price for 2004 was $41.38 per barrel of oil and $6.18 per MMBtu of natural gas. For the year ended December 31, 2004 the thresholds were $34.23 per barrel of oil and $4.28 per MMBtu of natural gas, subject to finalization of the adjustment for the 2004 GDP implicit price deflator. The Company was required to make monthly royalty payments for 2004 gas production. The Company accrued payments for 2004 oil royalties and will be required to pay these royalties to the MMS in the first quarter of 2005 after finalization of the price threshold. The Company will be required to make monthly royalty payments for both oil and gas production for 2005.

In the year succeeding the year in which any of the Company's properties became subject to royalties as the result of the average NYMEX price exceeding the price threshold, the portion of reserves attributable to potential future royalties would not be included in a year-end reserve report. However, if the average NYMEX prices were below the price thresholds in subsequent years, our reserves would be increased to reflect reserves previously attributed to future royalties. As a result, reported oil and gas reserves could materially increase or decrease, depending on the relation of price thresholds versus the average NYMEX prices. The reduction in revenues resulting from an obligation to pay these royalties and subsequent reduction of proved reserves could have a material adverse effect on the Company's results of operations and financial condition. The Company's reserve report as of December 31, 2004 excluded oil and gas reserves for Medusa that are subject to MMS royalties as a result of the average 2004 NYMEX prices for oil and gas exceeding the price thresholds.

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. ASSET RETIREMENT OBLIGATIONS

As discussed in Note 2, the Company adopted SFAS 143 on January 1, 2003. The impact of adopting the statement resulted in a gain of $181,000, net of tax, which was reported as a cumulative effect of change in accounting principle.

Approximately $30.3 million was recorded as the present value of asset retirement obligations on January 1, 2003 with the adoption of SFAS 143 related to the Company's oil and gas properties. Interest is accreted on this amount and reported as accretion expense in the Consolidated Statements of Operations.

Assets, primarily short-term U.S. Government securities, of approximately $7.7 million at December 31, 2004, of which $2.1 million is current, are recorded as restricted investments. These assets are held in abandonment trusts dedicated to pay future abandonment costs of oil and gas properties in which the Company has sold a net profits interest. If there is any excess of trust assets over abandonment costs, the excess will be distributed to the net profits interest owners.

The following table summarizes the activity for the Company's asset retirement obligation:

	Twelve Months Ended	
	December 31, 2004	December 31, 2003
Asset retirement obligation at beginning of period	$ 33,691	$ —
Liability recognized upon adoption	—	30,251
Accretion expense	3,400	2,884
Net profits interest accretion	459	371
Liabilities incurred	3,065	3,649
Liabilities settled	(2,076)	(2,847)
Revisions to estimate	(257)	(617)
Asset retirement obligation at end of period	38,282	33,691
Less: current retirement obligation	(13,300)	(8,571)
Long-term retirement obligation	$ 24,982	$ 25,120

Pro forma net income and earnings per share are not presented for the 12 months ended December 31, 2002 because the pro forma application of SFAS 143 to the prior periods would not result in pro forma net income and earnings per share materially different from the actual amounts reported for the periods in the accompanying Consolidated Statements of Operations.

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9. 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,		
	2004	2003	2002
		(In thousands)	
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$802,912	$762,918	$704,937
Property acquisition costs	1,355	1,154	1,471
Exploration costs	26,749	21,390	17,851
Development costs	32,004	33,972	43,151
SFAS 143-Asset Retirement Obligation	(918)	18,002	—
Medusa Spar transaction	—	(33,542)	—
Sale of mineral interests	(1)	(982)	(4,492)
End of period balance	$862,101	$802,912	$762,918
Unevaluated Properties (excluded from amortization) -			
Beginning of period balance	$ 34,251	$ 40,997	$ 37,560
Additions	16,367	5,228	5,802
Capitalized interest	4,577	4,862	5,289
Transfers to evaluated	(16,153)	(16,836)	(7,654)
End of period balance	$ 39,042	$ 34,251	$ 40,997
Accumulated depreciation, depletion and amortization-			
Beginning of period balance	$447,000	$426,254	$399,339
Provision charged to expense	47,453	28,195	26,915
Cumulative effect of change in accounting Principle	—	(7,449)	—
End of period balance	$494,453	$447,000	$426,254

Unevaluated property costs, primarily lease acquisition costs incurred at federal and state lease sales, unevaluated drilling costs, capitalized interest and general and administrative costs being excluded from the amortizable evaluated property base, consisted of $10.2 million incurred in 2004, $7.5 million incurred in 2003 and $21.3 million incurred in 2002 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 $2.18, $2.03 and $1.73 for the years ended December 31, 2004, 2003, and 2002, 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. 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 prices 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.

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 prices 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.

10. CONSOLIDATING CONDENSED FINANCIAL INFORMATION

Certain of the Company's subsidiaries have fully and unconditionally guaranteed the payment of all obligations under the Company's $200 million 9.75% Senior Notes due 2010 and the $175 million senior secured credit facility. The following tables present the consolidating condensed financial information of Callon Petroleum Company, as the parent company, and guarantor subsidiaries of Callon Petroleum Company balance sheets as of December 31, 2004 and December 31, 2003, and statements of income and cash flows for the twelve-month periods ended December 31, 2004, December 31, 2003 and December 31, 2002.

Callon Petroleum Company
Consolidating Condensed Guarantor Subsidiaries and Parent Company
Financial Information As of December 31, 2004 and December 31, 2003
And For The Twelve-Month Periods Ended
December 31, 2004, December 31, 2003 and December 31, 2002
Unaudited
(In thousands)

	Callon Petroleum Company (Parent Obligor)	Guarantor Subsidiaries	Consolidating and Eliminating Entries	Callon Petroleum Company Consolidated
		As of December 31, 2004		
Balance Sheet				
Current assets	$ 728	$ 27,348	$ —	$ 28,076
Intercompany receivables	297,480	—	(297,480)	—
Investment in subsidiaries	90,253	1,903	(92,156)	—
Oil and gas properties	1,463	405,227	—	406,690
Other assets	2,357	20,400	—	22,757
Total assets	$ 392,281	$ 454,878	$ (389,636)	$ 457,523
Current liabilities	$ 634	$ 40,482	—	41,116
Intercompany payables	—	297,480	(297,480)	—
Long-term debt, less current maturities	191,216	1,135	—	192,351
Other accrued liabilities	236	25,508	—	25,744
Stockholders' equity	200,195	90,273	(92,156)	198,312
Total liabilities and stockholders' equity	$ 392,281	$ 454,878	$ (389,636)	$ 457,523

	Callon Petroleum Company (Parent Obligor)	Guarantor Subsidiaries	Consolidating and Eliminating Entries	Callon Petroleum Company Consolidated
	As of December 31, 2003			
Balance Sheet				
Current assets	$ 64,300	$ 21,468	$ —	$ 85,768
Intercompany receivables	317,394	—	(317,394)	—
Investment in subsidiaries	54,247	2,039	(56,286)	—
Oil and gas properties	3,129	387,034	—	390,163
Other assets	1,557	18,544	—	20,101
Total assets	$ 440,627	$ 429,085	$ (373,680)	$ 496,032
Current liabilities	$ 93,846	$ 26,751	$ —	$ 120,597
Intercompany payables	—	317,394	(317,394)	—
Long-term debt, less current maturities	213,173	1,712	—	214,885
Other accrued liabilities	327	26,962	—	27,289
Stockholders' equity	133,281	56,266	(56,286)	133,261
Total liabilities and stockholders' equity	$ 440,627	$ 429,085	$ (373,680)	$ 496,032

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	Callon Petroleum Company (Parent Obligor)	Guarantor Subsidiaries	Consolidating and Eliminating Entries	Callon Petroleum Company Consolidated
	For The Twelve Months Ended December 31, 2004			
Statement of Income				
Operating revenues:				
Oil and gas sales	$ 4,614	$ 115,188	$ —	$ 119,802
Total operating revenues	4,614	115,188	—	119,802
Operating expenses:				
Lease operating expenses	472	21,836	—	22,308
Depreciation, depletion and amortization	1,772	45,681	—	47,453
General and administrative	1,652	7,106	—	8,758
Accretion expense	13	3,387	—	3,400
Derivative expense	—	1,371	—	1,371
Total operating expenses	3,909	79,381	—	83,290
Income from operations	705	35,807	—	36,512
Other (income) expenses:				
Interest expense	403	19,734	—	20,137
Other income	(252)	(105)	—	(357)
Loss on early extinguishment of debt	60	2,944	—	3,004
Equity in earnings of subsidiaries	(21,007)	—	21,007	—
Total other (income) expenses	(20,796)	22,573	21,007	22,784
Income (loss) before income taxes	21,501	13,234	(21,007)	13,728
Income tax expense (benefit)	—	(6,697)	—	(6,697)
Income (loss) before Medusa Spar LLC	21,501	19,931	(21,007)	20,425
Income from Medusa Spar LLC, net of tax	—	1,076	—	1,076
Net Income (loss)	21,501	21,007	(21,007)	21,501
Preferred stock dividends	1,272	—	—	1,272
Net income	$ 20,229	$ 21,007	$ (21,007)	$ 20,229

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	Callon Petroleum Company (Parent Obligor)	Guarantor Subsidiaries	Consolidating and Eliminating Entries	Callon Petroleum Company Consolidated
	For The Twelve Months Ended December 31, 2003			
Statement of Income				
Operating revenues:				
Oil and gas sales	$ 4,108	$ 69,589	$ —	$ 73,697
Total operating revenues	4,108	69,589	—	73,697
Operating expenses:				
Lease operating expenses	452	10,849	—	11,301
Depreciation, depletion and amortization	1,624	26,629	—	28,253
General and administrative	1,260	3,453	—	4,713
Accretion expense	20	2,864	—	2,884
Derivative expense	—	535	—	535
Total operating expenses	3,356	44,330	—	47,686
Income from operations	752	25,259	—	26,011
Other (income) expenses:				
Interest expense	704	29,910	—	30,614
Other income	(199)	(245)	—	(444)
Loss on early extinguishment of debt	128	5,445	—	5,573
Equity in earnings of subsidiaries	20,697	—	(20,697)	—
Total other (income) expenses	21,330	35,110	(20,697)	35,743
Income (loss) before income taxes	(20,578)	(9,851)	20,697	(9,732)
Income tax expense (benefit)	(2,553)	10,985	—	8,432
Income (loss) before Medusa Spar LLC and cumulative effect of change in accounting principle	(18,025)	(20,836)	20,697	(18,164)
Loss from Medusa Spar LLC, net of tax	—	(8)	—	(8)
Income (loss) before cumulative effect of change in accounting principle	(18,025)	(20,844)	(20,697)	(18,172)
Cumulative effect of change in accounting principle, net of tax	34	147	—	181
Net Income (loss)	(17,991)	(20,697)	20,697	(17,991)
Preferred stock dividends	1,277	—	—	1,277
Net income	$ (19,268)	$ (20,697)	$ 20,697	$ (19,268)

Statement of Income	Callon Petroleum Company (Parent Obligor)	Guarantor Subsidiaries	Consolidating and Eliminating Entries	Callon Petroleum Company Consolidated
	For The Twelve Months Ended December 31, 2002			
Operating revenues:				
Oil and gas sales	$ 3,064	$ 58,107	$ —	$ 61,171
Total operating revenues	3,064	58,107	—	61,171
Operating expenses:				
Lease operating expenses	1,273	9,757	—	11,030
Depreciation, depletion and amortization	1,579	25,517	—	27,096
General and administrative	1,163	3,542	—	4,705
Accretion expense	—	—	—	—
Derivative expense	—	708	—	708
Total operating expenses	4,015	39,524	—	43,539
Income from operations	(951)	18,583	—	17,632
Other (income) expenses:				
Interest expense	836	25,304	—	26,140
Other income	(1,623)	(4,314)	—	(5,937)
Loss on early extinguishment of debt	—	—	—	—
Equity in earnings of subsidiaries	1,565	—	(1,565)	—
Total other (income) expenses	778	20,990	(1,565)	20,203
Income (loss) before income taxes	(1,729)	(2,407)	1,565	(2,571)
Income tax expense (benefit)	(58)	(842)	—	(900)
Income (loss) before cumulative effect of change in accounting principle	(1,671)	(1,565)	1,565	(1,671)
Cumulative effect of change in accounting principle, net of tax	—	—	—	—
Net Income (loss)	(1,671)	(1,565)	1,565	(1,671)
Preferred stock dividends	1,277	—	—	1,277
Net income	$ (2,948)	$ (1,565)	$ 1,565	$ (2,948)

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Statement of Cash Flow	Callon Petroleum Company (Parent Obligor)	Guarantor Subsidiaries	Consolidating and Eliminating Entries	Callon Petroleum Company Consolidated
	For The Twelve Months Ended December 31, 2004			
Net cash provided (used in) operating activities	$ 10,315	$ 60,593	$ —	$ 70,908
Net cash provided by (used in) investing activities	(210)	(64,100)	—	(64,310)
Net cash provided by (used in) financing activities	(10,580)	(1,452)	—	(12,032)
Net increase (decrease) in cash and cash equivalents	(475)	(4,959)	—	(5,434)
Cash and cash equivalents at beginning of the period	486	8,214	—	8,700
Cash and cash equivalents at end of the period	$ 11	$ 3,255	$ —	$ 3,266

Statement of Cash Flow	Callon Petroleum Company (Parent Obligor)	Guarantor Subsidiaries	Consolidating and Eliminating Entries	Callon Petroleum Company Consolidated
	For The Twelve Months Ended December 31, 2003			
Net cash provided (used in) operating activities	$ 3,547	$ 31,082	$ —	$ 34,629
Net cash provided by (used in) investing activities	(12)	(23,303)	—	(23,315)
Net cash provided by (used in) financing activities	(3,240)	(5,181)	—	(8,421)
Net increase (decrease) in cash and cash equivalents	295	2,598	—	2,893
Cash and cash equivalents at beginning of the period	191	5,616	—	5,807
Cash and cash equivalents at end of the period	$ 486	$ 8,214	$ —	$ 8,700

Statement of Cash Flow	Callon Petroleum Company (Parent Obligor)	Guarantor Subsidiaries	Consolidating and Eliminating Entries	Callon Petroleum Company Consolidated
	For The Twelve Months Ended December 31, 2002			
Net cash provided (used in) operating activities	$ (52,696)	$ 64,863	$ —	$ 12,167
Net cash provided by (used in) investing activities	4,044	(58,791)	—	(54,747)
Net cash provided by (used in) financing activities	48,326	(6,826)	—	41,500
Net increase (decrease) in cash and cash equivalents	(326)	(754)	—	(1,080)
Cash and cash equivalents at beginning of the period	517	6,370	—	6,887
Cash and cash equivalents at end of the period	$ 191	$ 5,616	$ —	$ 5,807

11. 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 (see Note 7) 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 disbursement of funds to 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. Estimated future revenues and costs associated with the NPI and the Trusts are also excluded from the oil and gas reserve disclosures at Note 14. As of December 31, 2004 and 2003, the Trusts’ assets (all cash and investments) totaled $7,742,000 and $7,420,000 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. SFAS 143, discussed in Note 2 and 8, does not allow the Abandonment Trusts’ assets to be used to offset the associated abandonment liability. The Company did not record any income or loss associated with the Trust asset or abandonment liability as a result of adoption of SFAS 143.

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.

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.

12. EMPLOYEE BENEFIT PLANS

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

The Savings and Protection Plan provides employees with the option to defer receipt of a portion of their compensation and the Company may, at its discretion, match a portion of the employee's deferral with cash and Company Common Stock. The Company may also elect, at its discretion, to contribute a non-matching amount in cash and Company Common Stock to employees. The amounts held under the Savings and Protection Plan are invested in various funds maintained by a third party in accordance with the directions of each employee. An employee is fully vested, including Company discretionary contributions, immediately upon participation in the Savings and Protection Plan. The total amounts contributed by the Company, including the value of the common stock contributed, were $528,000, $562,000 and $611,000 in the years 2004, 2003 and 2002, respectively.

The 1994 Stock Incentive Plan (the "1994 Plan"), approved by the shareholders in 1994, 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 of 10 years from the date of grant.

On August 23, 1996, the Board of Directors of the Company approved and adopted the Callon Petroleum Company 1996 Stock Incentive Plan (the "1996 Plan"). The 1996 Plan was approved by the shareholders in 1997 and 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 the date of grant.

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 was amortized over the three-year vesting period of the options. Compensation costs of $27,000 and $416,000 were recognized in 2003, and 2002, respectively, related to these options.

In 2004, the Company awarded 430,000 performance shares from the 1994 and 1996 Plans. These shares vest to the recipients over a five-year period (one-fifth in each year) beginning in July 2005. The deferred compensation portion of this grant will be amortized to expense over the vesting period. The non-cash amortization expense in 2004 was $532,000. In addition, 25,000 stock options were awarded to directors at $12.40 from the 1994 Plan.

On February 14, 2002, the Board of Directors of the Company approved and adopted the 2002 Stock Incentive Plan (the “2002 Plan”). Pursuant to the 2002 Plan, 350,000 shares of common stock shall be reserved for issuance upon the exercise of options or for grants of stock options, stock appreciation rights or units, bonus stock, or performance shares or units. This Plan qualified as a “broadly based” plan under the provisions of the New York Stock Exchange’s rules and regulations and therefore did not require shareholder approval. Because the 2002 Plan is a broadly based plan, the aggregate number of shares underlying awards granted to officers and directors cannot exceed 50% of the total number of shares underlying the awards granted to all employees during any three-year period.

In 2002, the Company awarded 300,000 shares of restricted stock from the 1996 and the 2002 Plan and 70,500 from treasury shares to be issued as vested. The issuance of the restricted stock using treasury shares did not require shareholder approval pursuant to the New York Stock Exchange’s rules and regulations, and therefore shareholder approval was not sought. These shares will generally vest to the recipients over a three-year period (one-third in each year) beginning in November 2002. The deferred compensation portion of this grant will be amortized to expense over the vesting period. The non-cash amortization expense in 2004, 2003 and 2002 was $374,000, $454,000 and $496,000, respectively.

In 1997, the Board of Directors authorized the implementation of the Callon Petroleum Company 1997 Employee Stock Purchase Plan (the “1997 Purchase Plan”), which was approved by the Company’s shareholders at the 1997 Annual Meeting. The Plan provides eligible employees of the Company with the opportunity to acquire a proprietary interest in the Company through participation in a payroll deduction-based employee stock purchase plan. An aggregate of 250,000 shares of common stock have been reserved for issuance over the 10-year term of the 1997 Purchase Plan. The purchase price per share at which common stock will be purchased on the participant’s behalf on each purchase date within an offering period is equal to 85 percent of the fair market value per share of common stock. As of December 31, 2004 there were no remaining shares available for purchase.

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

	2004		2003		2002	
	Shares	**Wtd Avg Ex Price**	**Shares**	**Wtd Avg Ex Price**	**Shares**	**Wtd Avg Ex Price**
Outstanding, beginning of year	2,450,867	$ 9.84	2,520,417	$ 9.90	2,332,667	$ 10.84
Granted (at market)	25,000	12.40	30,000	5.12	310,000	4.45
Exercised	(437,918)	9.74	(500)	4.10	—	—
Forfeited	(525,350)	9.80	(99,050)	9.74	(122,250)	14.10
Expired	—	—	—	—	—	—
Outstanding, end of year	1,512,599	$ 9.93	2,450,867	$ 9.84	2,520,417	$ 9.90
Exercisable, end of year	1,446,486	$ 10.20	2,262,067	$ 10.31	2,224,334	$ 10.57
Weighted average fair value of options granted (at market)	$ 4.48		$ 2.97		$ 2.44	

The following table sets forth additional information regarding options outstanding at December 31, 2004. Contractual life and exercise prices represent weighted averages for options outstanding and options exercisable.

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number Outstanding	Contractual Life (years)	Exercise Price	Number Exercisable	Exercise Price
$ 3.70 to $ 6.41	237,999	7.5	$ 4.56	171,886	$ 4.72
$ 9.00 to $ 12.40	1,209,600	3.9	$ 10.76	1,209,600	$ 10.76
$13.56 to $ 15.31	65,000	3.2	$ 14.16	65,000	$ 14.16

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:

	2004	2003	2002
Risk free interest rate	3.7%	4.0%	3.7%
Expected life (years)	5.0	5.0	5.0
Expected volatility	45.1%	65.3%	61.0%
Expected dividends	—	—	—

13. EQUITY TRANSACTIONS

On June 22, 2004, we closed the public offering of three million shares of common stock priced at $13.25 per share raising net proceeds of approximately $38.2 million, after expenses. In addition, we granted the underwriter, Johnson Rice & Company L.L.C., an over-allotment option to purchase an additional 450,000 shares. On June 30, 2004, the underwriter exercised the over-allotment option for an additional 450,000 shares priced at $13.25 per share, raising the net proceeds of the offering by approximately $5.7 million, after expenses. The proceeds from the transactions were used to redeem $33 million of the 11% Senior Subordinated Notes due December 15, 2005 and for general corporate purposes.

In November 1995, the Company sold 1,315,500 shares of $2.125 Convertible Exchangeable Preferred Stock, Series A, and $0.01 par value per share (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 issuance of the Preferred Stock, after underwriters discount and expenses, were $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 non-cash premium negotiated in excess of the conversion rate was recorded as additional preferred stock dividends and excluded from the Consolidated Statements of Cash Flows.

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. 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.

14. SUPPLEMENTAL OIL AND GAS RESERVE DATA (UNAUDITED)

The Company's proved oil and gas reserves at December 31, 2004, 2003 and 2002 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 to exclude reserves attributable to the volumetric production payment described in Note 2.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represents estimates only and should not be construed as being exact. In addition, the standardized 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. See Note 7 regarding the Deep Water Royalty Relief Act and the loss of 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,		
	2004	2003	2002
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	23,709	24,043	30,209
Revisions to previous estimates	(2,370)(b)	(1)	(8,699)(a)
Purchase of reserves in place	—	—	—
Sales of reserves in place	—	(65)	—
Extensions and discoveries	145	—	2,759(a)
Production	(1,736)	(268)	(226)
End of period	19,748	23,709	24,043
Natural Gas (MMcf):			
Beginning of period	74,691	91,539	120,299
Revisions to previous estimates	2,138	(6,407)(b)	(19,284)(a)
Purchase of reserves in place	—	—	—
Sales of reserves in place	—	(49)	—
Extensions and discoveries	7,177	1,923	3,584(a)
Production	(11,387)	(12,315)	(13,060)
End of period	72,619	74,691	91,539
Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	9,919	1,056	885
End of period	10,292	9,919	1,056
Natural Gas (MMcf):			
Beginning of period	31,415	37,631	51,221
End of period	33,982	31,415	37,631

(a) For the year ended December 31, 2002, revisions to previous estimates and extensions and discoveries were adjusted from the amounts reported in the Company's Annual Report on Form 10-K dated March 27, 2003 to reflect the subsequent changes in properties that were part of property acquisitions or exploratory drilling programs and should have been classified as extensions instead of revisions.

(b) Includes Medusa royalty adjustment

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 (approximately $6.51 per Mcf for natural gas and $36.72 per Bbl for oil for the 2004 disclosures, $5.99 per Mcf and $30.50 per Bbl for 2003 disclosures, and $4.80 per Mcf and $34.22 per Bbl for 2002 disclosures) at each date presented and have not been escalated. 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,		
	2004	2003	2002
		(In thousands)	
Future cash inflows	$1,198,096	$ 1,170,118	$1,261,571
Future costs -			
Production	(231,616)	(219,421)	(165,559)
Development and net abandonment	(74,335)	(111,850)	(125,813)
Future net inflows before income taxes	892,145	838,847	970,199
Future income taxes	(166,284)	(89,567)	(119,020)
Future net cash flows	725,861	749,280	851,179
10% discount factor	(209,968)	(230,254)	(295,133)
Standardized measure of discounted future net cash flows	$ 515,893	$ 519,026	$ 556,046

Changes in Standardized Measure

	Years Ended December 31,		
	2004	2003	2002
		(In thousands)	
Standardized measure – beginning of period	$519,026	$ 556,046	$ 254,857
Sales and transfers, net of production costs	(97,494)	(62,396)	(38,375)
Net change in sales and transfer prices, net of production costs	86,551	(41,011)	401,837
Exchange and sale of in place reserves	—	(1,226)	—
Purchases, extensions, discoveries, and improved recovery, net of future production and development costs incurred	77,576	25,632	8,456
Revisions of quantity estimates	(41,314)	(18,018)	(103,452)
Accretion of discount	57,046	62,394	26,915
Net change in income taxes	(45,262)	16,460	(53,608)
Changes in production rates, timing and other	(40,236)	(18,855)	59,416
Standardized measure — end of period	$515,893	$ 519,026	$ 556,046

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15. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
2004				
Total revenues	$31,919	$37,606	$25,138	$25,139
Income from operations	10,231	14,543	5,367	6,371
Net income (loss)	2,102	9,730	546	9,123(a)
Net income (loss) per common share-basic	$ 0.13	$ 0.66	$ 0.01	$ 0.50(a)
Net income (loss) per common share-diluted	0.12	0.58	0.01	0.45(a)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
2003				
Total revenues	$21,268	$ 18,409	$ 15,082	$ 18,938
Income from operations	8,946	6,422	4,366	6,277
Income (loss) before cumulative effect of change in accounting principle	1,201	(647)	(2,026)	(16,700)(b)
Net income (loss)	1,382	(647)	(2,026)	(16,700)(b)
Net income (loss) per common share-basic:				
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 0.07	($ 0.07)	($ 0.17)	($ 1.24)(b)
Cumulative effect of change in accounting principle, net of tax	0.01	0.00	0.00	0.00
Net income (loss) per share	$ 0.08	($ 0.07)	($ 0.17)	($ 1.24)(b)
Net income (loss) per common share-diluted:				
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 0.07	($ 0.07)	($ 0.17)	($ 1.24)(b)
Cumulative effect of change in accounting principle, net of tax	0.01	0.00	0.00	0.00
Net income (loss) per share	$ 0.08	($ 0.07)	($ 0.17)	($ 1.24)(b)

(a) The fourth quarter of 2004 includes a tax benefit of $6.7 million resulting from the elimination of the valuation allowance established in 2003. See Note 3.

(b) The fourth quarter of 2003 includes the establishment of a deferred tax valuation allowance of $11.5. See Note 3.

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

There have been no disagreements with the independent auditors on any matters of accounting principles or practices, financial statement disclosure, or auditing scope or procedures.

ITEM 9.A CONTROLS AND PROCEDURES

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act. This term refers to the controls and procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission. Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this annual report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this annual report.

Management's Report On Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2004 based on the frame work in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control-Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2004.

Ernst & Young LLP, our independent registered public accounting firm, has issued an attestation report on our management's assessment of the effectiveness of our internal control over financial reporting which is included herein.

Changes In Internal Control Over Financial Reporting

There were no changes to our internal control over financial reporting during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

The Stockholders and Board of Directors
Callon Petroleum Company

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Callon Petroleum Company maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Callon Petroleum Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Callon Petroleum Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Callon Petroleum Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Callon Petroleum Company as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2004 of Callon Petroleum Company and our report dated March 8, 2005, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 8, 2005

ITEM 9.B OTHER INFORMATION

We have disclosed all information required to be disclosed in a current report on Form 8-K during the fourth quarter of the year ended December 31, 2004 in previously filed reports on Form 8-K.

PART III.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

For information concerning Item 10, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 5, 2005 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION.

For information concerning Item 11, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 5, 2005 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

For information concerning the security ownership of certain beneficial owners and management, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 5, 2005 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2004 regarding the number of shares of Common Stock that may be issued under the Company's equity compensation plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights **(a)**	Weighted-average exercise price of outstanding options, warrants and rights **(b)**	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) **(c)**
Equity compensation plans approved by security holders	1,370,266	$ 10.51	501,726
Equity compensation plans not approved by security holders	142,333	$ 4.36	65,666
Total	1,512,599	$ 9.93	567,392

See Note 12 to the Consolidated Financial Statements for a description of the material provisions of each equity compensation plan under which our equity securities are authorized for issuance that was adopted without the approval of shareholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

For information concerning Item 13, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 5, 2005 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

For information concerning Item 14, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 5, 2005 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

PART IV.

ITEM 15. 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 44 through 79.

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of the Years Ended December 31, 2004 and 2003

Consolidated Statements of Operations for the Three Years in the Period Ended December 31, 2004

Consolidated Statements of Stockholders' Equity for the Three Years in the Period Ended December 31, 2004

Consolidated Statements of Cash Flows for the Three Years in the Period Ended December 31, 2004

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 to Exhibit 3.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

   3.2 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)

   3.3 Certificate of Amendment to Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

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 as corrected (included as part of Exhibit 3.1)

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 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)

4.6 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)

4.7 Form of Warrant entitling certain holders of the Company's 10.125% Senior Subordinated Notes due 2002 to purchase common stock from the Company (incorporated by reference to Exhibit 4.13 of the Company's Form 10-Q for the period ended June 30, 2002, File No. 001- 14039)

4.8 Form of Warrants dated December 8, 2003 and December 29, 2003 entitling lenders under the Company's $185 million amended and restated senior unsecured credit agreement dated December 23, 2003 to purchase common stock from the Company (incorporated by reference to Exhibit 4.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

4.9 Indenture for the Company's 9.75% Senior Notes due 2010, dated March 15, 2004 between Callon Petroleum Company and American Stock Transfer and Trust Company (incorporated by reference to Exhibit 4.16 of the Company's Quarterly Report on Form 10-Q for the period ended March 31, 2004, 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)

10.2 Counterpart to Registration Rights Agreement by and between the Company, Ganger Rolf ASA and Bonheur ASA. (incorporated by reference from Exhibit 10.2 of the Company's Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 001-14039)

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

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

10.5 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)

10.6 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)

10.7 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)

10.8 Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.9 Change of Control Severance Compensation Agreement by and between Callon Petroleum and John S. Weatherly dated January 1, 2002 (incorporated by reference to Exhibit 10.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.10 Change of Control Severance Compensation Agreement by and between Callon Petroleum Company and Fred L. Callon, dated January 1, 2002 (incorporated by reference to Exhibit 10.15 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.11 Change of Control Severance Compensation Agreement by and between Callon Petroleum and Dennis W. Christian, dated January 1, 2002 (incorporated by reference to Exhibit 10.16 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.12 Medusa Spar Agreement dated as of August 8, 2003, among Callon Petroleum Operating Company, Murphy Exploration & Production Company-USA and Oceaneering International, Inc. (incorporated by reference to Exhibit 10.19 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

10.13 Credit Agreement dated as of December 18, 2003 among Medusa Spar LLC, The Bank of Nova Scotia, as Administrative Agent, Bank One, N.A., Sun Trust Bank, as Syndication Agents and other Lenders Party. (incorporated by reference to Exhibit 10.20 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

10.14 The Retirement Package and Release Agreement made, entered into and effective March 9, 2004 between Callon Petroleum Company and Dennis W. Christian. (incorporated by reference to Exhibit 10.21 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

10.15 The Retirement Package and Release Agreement made, entered into and effective March 9, 2004 between Callon Petroleum Company and Kathy G. Tilley. (incorporated by reference to Exhibit 10.22 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

10.16 Credit Agreement dated as of June 14, 2004 between the Company and Union Bank of California, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated June 14, 2004, File No. 001-14039)

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*

14. Code of Ethics

14.1 Code of Ethics for Chief Executive Officers and Senior Financial Officers (incorporated by reference to Exhibit 14.1 of the Company's Annual report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

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 Ernst & Young LLP

23.2 Consent of Huddleston & Co., Inc.

24. Power of attorney*

31. Rule 13a-14(a) Certifications

31.1 Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)

31.2 Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)

32. Section 1350 Certifications

    32.1 Certification of Chief Executive Officer pursuant to Rule 13(a)-14(b)

    32.2 Certification of Chief Financial Officer pursuant to Rule 13(a)-14(b)

99. Additional Exhibits*

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*Inapplicable to this filing.

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 10, 2005	/s/Fred L. Callon Fred L. Callon (principal executive officer, director)
Date: March 10, 2005	/s/John S. Weatherly John S. Weatherly (principal financial officer)
Date: March 10, 2005	/s/Rodger W. Smith Rodger W. Smith (principal accounting officer)
Date: March 10, 2005	/s/John S. Callon John S. Callon (director)
Date: March 10, 2005	/s/Richard Flury Richard Flury (director)
Date: March 10, 2005	/s/Robert A. Stanger Robert A. Stanger (director)
Date: March 10, 2005	/s/John C. Wallace John C. Wallace (director)
Date: March 10, 2005	/s/B. F. Weatherly B. F. Weatherly (director)
Date: March 10, 2005	/s/Richard O. Wilson Richard O. Wilson (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 10, 2005	By: /s/John S. Weatherly John S. Weatherly, Senior Vice President and Chief Financial Officer

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

   4.3 Designation for Convertible, Exchangeable Preferred Stock, Series A as corrected (included as part of Exhibit 3.1)

   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 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)

   4.6 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)

   4.7 Form of Warrant entitling certain holders of the Company's 10.125% Senior Subordinated Notes due 2002 to purchase common stock from the Company (incorporated by reference to Exhibit 4.13 of the Company's Form 10-Q for the period ended June 30, 2002, File No. 001- 14039)

   4.8 Form of Warrants dated December 8, 2003 and December 29, 2003 entitling lenders under the Company's $185 million amended and restated senior unsecured credit agreement dated December 23, 2003 to purchase common stock from the Company (incorporated by reference to Exhibit 4.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

   4.9 Indenture for the Company's 9.75% Senior Notes due 2010, dated March 15, 2004 between Callon Petroleum Company and American Stock Transfer and Trust Company (incorporated by reference to Exhibit 4.16 of the Company's Quarterly Report on Form 10-Q for the period ended March 31, 2004, File No. 001-14039)

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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)

10.2 Counterpart to Registration Rights Agreement by and between the Company, Ganger Rolf ASA and Bonheur ASA. (incorporated by reference from Exhibit 10.2 of the Company's Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 001-14039)

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

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

10.5 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)

10.6 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)

10.7 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)

10.8 Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.9 Change of Control Severance Compensation Agreement by and between Callon Petroleum and John S. Weatherly dated January 1, 2002 (incorporated by reference to Exhibit 10.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.10 Change of Control Severance Compensation Agreement by and between Callon Petroleum Company and Fred L. Callon, dated January 1, 2002 (incorporated by reference to Exhibit 10.15 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.11 Change of Control Severance Compensation Agreement by and between Callon Petroleum and Dennis W. Christian, dated January 1, 2002 (incorporated by reference to Exhibit 10.16 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.12 Medusa Spar Agreement dated as of August 8, 2003, among Callon Petroleum Operating Company, Murphy Exploration & Production Company-USA and Oceaneering International, Inc. (incorporated by reference to Exhibit 10.19 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

10.13 Credit Agreement dated as of December 18, 2003 among Medusa Spar LLC, The Bank of Nova Scotia, as Administrative Agent, Bank One, N.A., Sun Trust Bank, as Syndication Agents and other Lenders Party. (incorporated by reference to Exhibit 10.20 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

10.14 The Retirement Package and Release Agreement made, entered into and effective March 9, 2004 between Callon Petroleum Company and Dennis W. Christian. (incorporated by reference to Exhibit 10.21 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

10.15 The Retirement Package and Release Agreement made, entered into and effective March 9, 2004 between Callon Petroleum Company and Kathy G. Tilley. (incorporated by reference to Exhibit 10.22 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

10.16 Credit Agreement dated as of June 14, 2004 between the Company and Union Bank of California, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K dated June 14, 2004, File No. 001-14039)

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*

14. Code of Ethics

    14.1 Code of Ethics for Chief Executive Officers and Senior Financial Officers (incorporated by reference to Exhibit 14.1 of the Company's Annual report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

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 Ernst & Young LLP

    23.2 Consent of Huddleston & Co., Inc.

24. Power of attorney*

31. Rule 13a-14(a) Certifications

    31.1 Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)

    31.2 Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)

32. Section 1350 Certifications

    32.1 Certification of Chief Executive Officer pursuant to Rule 13(a)-14(b)

    32.2 Certification of Chief Financial Officer pursuant to Rule 13(a)-14(b)

99. Additional Exhibits*

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*Inapplicable to this filing.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements (File Nos. 333-100646, 333-87945, 333-60606, 333-47784, 333-29537, 333-29529, 333-90410, 333-109744 and 333-116308) of Callon Petroleum Company of our reports dated March 8, 2005, with respect to the consolidated financial statements of Callon Petroleum Company, Callon Petroleum Company management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of Callon Petroleum Company, included in this Annual Report (Form 10-K) for the year ended December 31, 2004.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 8, 2005

Exhibit 23.2

CONSENT OF HUDDLESTON & CO., INC.

We hereby consent to the references to us and our reserve reports for the years ended December 31, 2004, 2003 and 2002 in Callon Petroleum Company's Annual Report on Form 10-K for the year ended December 31, 2004 and the incorporation by reference in the current and future effective Registration Statements of Callon Petroleum Company of the reference to us and our reserve reports for the years ended December 31, 2004, 2003 and 2002.

HUDDLESTON & CO., INC.

/s/ Peter D. Huddleston, P.E.

Peter D. Huddleston, P.E.
President

Houston, Texas
March 4, 2005

Exhibit 31.1

CERTIFICATIONS

I, Fred L. Callon, certify that:

1. I have reviewed this Annual Report on Form 10-K of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting;

Date: March 10, 2005

By: /s/ Fred L. Callon
Fred L. Callon, President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, John S. Weatherly, certify that:

1. I have reviewed this Annual Report on Form 10-K of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting

Date: March 10, 2005

By: /s/ John S. Weatherly

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

EXHIBIT 32.1

CERTIFICATION PURSUANT TO

18 U.S.C. SECTION 1350

In connection with the Annual Report of Callon Petroleum Company (the "***Company***") on Form 10-K for the fiscal year ended December 31, 2004, as filed with the Securities and Exchange Commission on the date hereof (the "***Report***"), I, Fred L. Callon, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of, and for the periods presented in the Report.

Dated: March 10, 2005

/s/ Fred L. Callon
Fred L. Callon, Chief Executive Officer

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

EXHIBIT 32.2

CERTIFICATION PURSUANT TO

18 U.S.C. SECTION 1350

In connection with the Annual Report of Callon Petroleum Company (the "***Company***") on Form 10-K for the fiscal year ended December 31, 2004, as filed with the Securities and Exchange Commission on the date hereof (the "***Report***"), I, John S. Weatherly, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of, and for the periods presented in the Report.

Dated: March 10, 2005

/s/ John S. Weatherly
John S. Weatherly, Chief Financial Officer

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.