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PrimeEnergy

PrimeEnergy Corporation

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ANNUAL REPORT
2004

President's Letter

PrimeEnergy had an outstanding year in 2004. We are pleased to report several significant accomplishments for our Company. First, the production of 5,138,000 mcf of natural gas was the largest quantity of natural gas produced in a single year. Second, the production of 371,000 barrels of oil was also the largest quantity of oil produced in a single year. Third, the Company as of December 31, 2004 had proved reserves of 44,870 bcf of natural gas and 2.932 million barrels of oil. Both of these reserve categories are the largest recorded in the Company's history. Fourth, the Company's revenues grew from $46,719,000 to $62,428,000 and earnings on a fully-diluted basis grew from $1.31 to $1.70 per share.

We are also proud of the accomplishments of our three wholly-owned well servicing subsidiaries, Eastern Oil Well Service Company, Southwest Oilfield Construction Company and EOWS Midland Company. We continue to invest our capital in these businesses by acquiring additional equipment and refurbishing our existing equipment. At the end of 2004 our oil field service equipment and facilities had a fair-market value of approximately $10,000,000.

While accomplishing the production growth, reserve growth and building well service operations, we have also retired 4,235,852 shares of stock since 1990 at an average price of $3.98. This represents approximately 55% of the outstanding common stock. The Company also retired 769,500 options at a cost of $607,000.

The Company's strategy is to develop a balanced portfolio of drilling opportunities that include low risk wells with a high probability of success and high risk wells with greater economic potential. The Company in the first quarter of 2005 was successful in drilling four low risk wells in Colorado and four successful lateral wells in the Gulf of Mexico, but also drilled one dry hole in Oklahoma. The four wells drilled in the Gulf of Mexico have the potential to add significant units of natural gas production to the Company in the fourth quarter of 2005.

It is with great sadness that I announce the passing of Michael M. Tyson and Dennis "Bob" Murphy. These two gentlemen contributed to the growth of PrimeEnergy over the years and they will be sorely missed.

PrimeEnergy remains committed to developing domestic reserves and building on our knowledge and operating presence in the Southwest, Appalachian Basin and the Gulf of Mexico. Ultimately, a corporation is dependent on the skill of its people and we believe that we have those people in place to continue to grow our business.

Sincerely,

Charles E. Drimal, Jr.
President, CEO

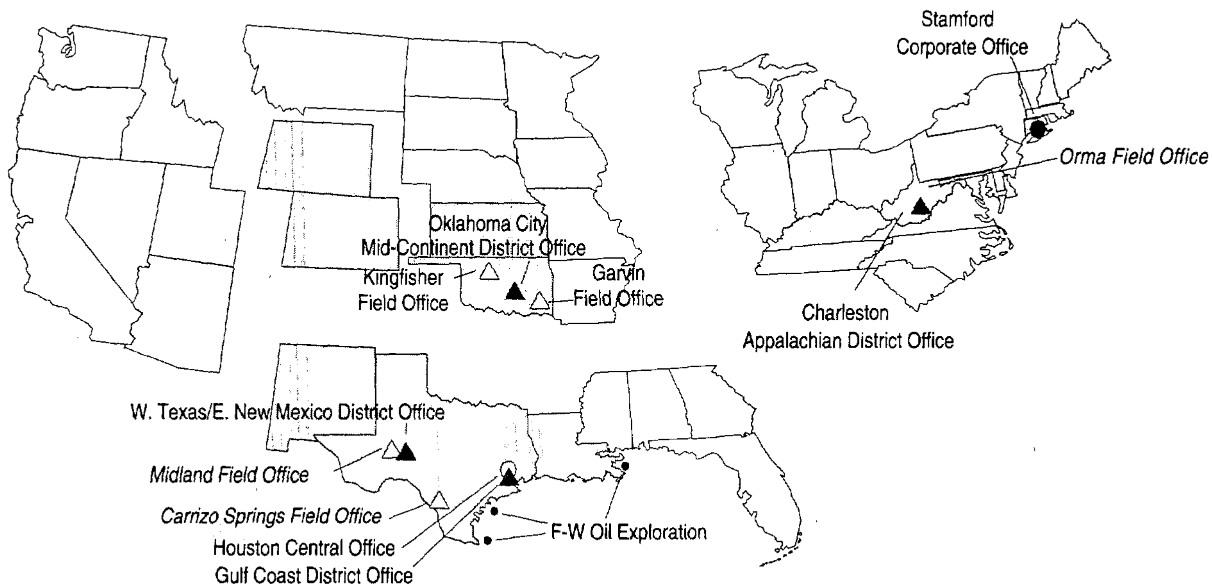
The Company

PrimeEnergy Corporation ("the Company") is an independent oil and gas company actively engaged in acquiring, developing and producing oil and natural gas. The Company's common stock shares are traded in the NASDAQ stock market under the symbol "PNRG."

The Company is headquartered in Stamford, Connecticut, with operating offices in Houston and Midland, Texas; Oklahoma City, Oklahoma and Charleston, West Virginia. PrimeEnergy owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the continental United States and in the Gulf of Mexico. The Company operates 1,542 wells and owns non-operating interests in 474 additional wells. The Company's off-shore operations in the Gulf of Mexico are conducted through its majority owned subsidiary, F-W Oil Exploration L.L.C.

Operations on-shore are conducted through the Company's subsidiary, Prime Operating Company, with its principal offices in Houston, Texas, and district offices in Oklahoma City, Oklahoma, Midland, Texas, and Charleston, West Virginia, with field offices in Oklahoma, Texas and West Virginia. Through its subsidiaries, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, and EOWS Midland Company, the Company provides well service support operations, site preparation and construction services for drilling and re-working operations, both in connection with the Company's activities and providing contract services for third parties.

The Company's Annual Report, Form 10-K for the year ended December 31, 2004, as filed with the Securities and Exchange Commission is reproduced herein (except for exhibits) as the Company's Annual Report for 2004 to its shareholders. The Form 10-K includes the Company's audited financial statements and other financial data and information, a description of the Company's business and properties and other pertinent information concerning the Company.



Selected Financial Data

The following table summarizes certain selected financial data to highlight significant trends in the Company's financial condition and results of operations for the periods indicated. The selected financial data should be read in conjunction with the Financial Statements and related notes included elsewhere in this Report.

	2004	2003	2002	2001	2000
Revenues	$62,428,000	46,719,000	34,186,000	42,408,000	39,182,000
Income from operations	$10,223,000	8,047,000	2,168,000	6,968,000	6,148,000
Net Income	$ 7,275,000	5,702,000	1,757,000	5,413,000	5,365,000
Income per common share	$ 2.04	1.56	0.47	1.39	1.26
Diluted net income per common share	$ 1.70	1.31	0.40	1.18	1.08
Net cash provided by operations	$26,995,000	19,622,000	9,644,000	12,313,000	11,498,000
Total assets	$69,926,000	58,255,000	44,909,000	35,816,000	35,094,000
Long-term obligations	$30,290,000	26,925,000	23,734,000	16,958,000	18,213,000
Cash dividends	None	None	None	None	None

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U.S. SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2004

or

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition Period From to

Commission File Number 0-7406

PrimeEnergy Corporation
(Exact name of registrant as specified in its charter)

Delaware (state or other jurisdiction of incorporation or organization)	**84-0637348** (I.R.S. Employer Identification No.)
One Landmark Square **Stamford, Connecticut** (Address of principal executive offices)	**06901** (Zip Code)

Registrant's telephone number, including area code: **(203) 358-5700**

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

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, par value $.10 per share
(Title of Class)

Indicate whether Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] **No** [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-B 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 12-b-2

Yes [ ] **No** [X]

The aggregate market value of the voting stock of the Registrant held by non-affiliates, computed by reference to the average bid and asked price of such common equity as of the last business day of the Registrant's most recently completed second fiscal quarter, was $26,772,385.

The number of shares outstanding of each class of the Registrant's Common Stock as of March 28, 2005, was: 3,477,850 shares, Common Stock, $0.10 par value,

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's proxy statement to be furnished to stockholders in connection with its Annual Meeting of Stockholders to be held in June, 2005, are incorporated by reference in Part III hereof.

PrimeEnergy Corporation

FORM 10-K ANNUAL REPORT
For the Fiscal Year Ended
December 31, 2004

PART I

Item 1. BUSINESS.

General

This Report contains forward-looking statements that are based on management's current expectations, estimates and projections. Words such as "expects," "anticipates," "intends," "plans," "believes," "projects" and "estimates," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, and are subject to the safe harbors created thereby. These statements are not guarantees of future performance and involve risks and uncertainties and are based on a number of assumptions that could ultimately prove inaccurate and, therefore, there can be no assurance that they will prove to be accurate. Actual results and outcomes may vary materially from what is expressed or forecast in such statements due to various risks and uncertainties. These risks and uncertainties include, among other things, volatility of oil and gas prices, competition, risks inherent in the Company's oil and gas operations, the inexact nature of interpretation of seismic and other geological and geophysical data, imprecision of reserve estimates, the Company's ability to replace and expand oil and gas reserves, and such other risks and uncertainties described from time to time in the Company's periodic reports and filings with the Securities and Exchange Commission. Accordingly, stockholders and potential investors are cautioned that certain events or circumstances could cause actual results to differ materially from those projected.

PrimeEnergy Corporation (the "Company") was organized in March, 1973, under the laws of the State of Delaware.

The Company is engaged in the oil and gas business through the acquisition, exploration, development, and production of crude oil and natural gas. The Company's properties are located primarily in Texas, Oklahoma, West Virginia, the Gulf of Mexico, New Mexico, and Louisiana. The Company, through its wholly-owned subsidiaries Prime Operating Company, Southwest Oilfield Construction Company, Eastern Oil Well Service Company and EOWS Midland Company, acts as operator and provides well servicing support operations for many of the onshore oil and gas wells in which the Company has an interest, as well as for third parties. The Company owns and operates properties in the Gulf of Mexico through its sixty percent owned subsidiary F-W Oil Exploration L.L.C. ("FW"). The Company is also active in the acquisition of producing oil and gas properties through joint ventures with industry partners. The Company's wholly-owned subsidiary, PrimeEnergy Management Corporation ("PEMC"), acts as the managing general partner of 18 oil and gas limited partnerships (the "Partnerships") of which two are publicly held, and acts as the managing trustee of two asset and income business trusts ("the Trusts").

Exploration, Development and Recent Activities

The Company's activities include development and exploratory drilling. The Company's strategy is to develop a balanced portfolio of drilling prospects that includes lower risk wells with a high probability of success and higher risk wells with greater economic potential.

As of December, 2004, the Company had net capitalized costs related to oil and gas properties of $48 million, including $13 million of properties under evaluation. Total expenditures for the acquisition, exploration and development of the Company's properties during 2004 was $25 million of which $5.5 million was related to exploration costs expensed during 2004.

Properties under evaluation include $7.5 million invested in one offshore well completed and tested during the third quarter of 2004, however, early production tests have been inconclusive as to the commercial viability of this prospect. Additional expenditures during 2005 will be required to determine whether production rates and ultimate recoverable reserves are sufficient to warrant the costs of setting a platform and installing production facilities. If this well is determined to be noncommercial, the write off of this investment in 2005 will have a significant negative impact on the Company's earnings.

As of December 31, 2004, our offshore properties had net proved reserves of 10.2 BCFE and net capitalized costs of $18.7 million. Approximately 70% of these reserves are undeveloped and will require substantial capital expenditures during 2005. As of March, 2005, the Company has spent approximately $7.8 million drilling four successful wells in the Gulf of Mexico as part of our program to develop these properties. Our offshore drilling budget for 2005 is $10 million and an additional $16 million has been committed to pipeline and facility construction and installation. Production from these wells, depending on flow rates and the timing of the completion of the pipelines and facilities, may add significant gas volumes to the Company's sales during the fourth quarter of 2005.

The Company's offshore properties include a non-operated interest in producing and undeveloped properties in the Breton Sound Block 41 Field. In February 2005, a working interest owner in the field completed the sale of their interest in this asset. The Company has not received an offer to purchase our interest in the field, however, based on the price of this transaction, the Company's ownership position has an equivalent value of approximately $24 million.

During 2004, onshore exploration and development expenditures totaled $9.3 million. Spending on projects in our core operating areas for 2005 is budgeted at $15 million. As of March, 2005, the Company has drilled four successful wells, one dry hole and is currently drilling two wells in these areas.

The Company believes that its diversified portfolio approach to its drilling activities results in more consistent and predictable economic results than might be experienced with a less diversified or higher risk drilling program profile.

The Company attempts to assume the position of operator in all acquisitions of producing properties. The Company will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which it owns interests and is actively pursuing the acquisition of producing properties. In order to diversify and broaden its asset base, the Company will consider acquiring the assets or stock in other entities and companies in the oil and gas business. The main objective of the Company in making any such acquisitions will be to acquire income producing assets so as to increase the Company's net worth and increase the Company's oil and gas reserve base.

The Company presently owns producing and non-producing properties located primarily in Texas, Oklahoma, West Virginia, the Gulf of Mexico, New Mexico, and Louisiana, and owns a substantial amount of well servicing equipment. The Company does not own any refinery or marketing facilities, and does not currently own or lease any bulk storage facilities or pipelines other than adjacent to and used in connection with producing wells and the interests in certain gas gathering systems. All of the Company's oil and gas properties and interests are located in the United States.

In the past, the supply of gas has exceeded demand on a cyclical basis, and the Company is subject to a combination of shut-in and/or reduced takes of gas production during summer months. Prolonged shut-ins could result in reduced field operating income from properties in which the Company acts as operator.

Exploration for oil and gas requires substantial expenditures particularly in exploratory drilling in undeveloped areas, or "wildcat drilling." As is customary in the oil and gas industry, substantially all of the Company's exploration and development activities are conducted through joint drilling and operating agreements with others engaged in the oil and gas business.

Summaries of the Company's oil and gas drilling activities, oil and gas production, and undeveloped leasehold, mineral and royalty interests are set forth under Item 2., "Properties," below. Summaries of the Company's oil and gas reserves, future net revenue and present value of future net revenue are also set forth under Item 2., "Properties – Reserves" below.

Well Operations

The Company's on-shore operations are conducted through a central office in Houston, Texas, and district offices in Houston and Midland, Texas, Oklahoma City, Oklahoma, and Charleston, West Virginia. The Company currently operates 1,542 oil and gas wells, 418 through the Houston office, 158 through the Midland office, 458 through the Oklahoma City office and 497 through the Charleston, West Virginia office. Substantially all of the wells operated by the Company are wells in which the Company has an interest. The Company's off-shore operations are conducted through FW, also in Houston, Texas.

The Company operates wells pursuant to operating agreements which govern the relationship between the Company as operator and the other owners of working interests in the properties, including the Partnerships, Trusts and joint venture participants. For each operated well, the Company receives monthly fees that are competitive in the areas of operations and also is reimbursed for expenses incurred in connection with well operations.

The Partnerships, Trusts and Joint Ventures

Since 1975, PEMC has acted as managing general partner of various partnerships, trusts and joint ventures.

PEMC, as managing general partner of the Partnerships and managing trustee of the Trusts, is responsible for all Partnership and Trust activities, including the review and analysis of oil and gas properties for acquisition, the drilling of development wells and the production and sale of oil and gas from productive wells. PEMC also provides administration, accounting and tax preparation for the Partnerships and Trusts. PEMC is liable for all debts and liabilities of the Partnerships and Trusts, to the extent that the assets of a given limited partnership or trust are not sufficient to satisfy its obligations. The Company stopped sponsoring partnerships and trusts in 1992. Today there are only 18 partnerships and two trusts remaining. The aggregate number of limited partners in the Partnerships and beneficial owners of the Trusts now administered by PEMC is approximately 3,730. This number, as well as the number of remaining partnerships noted above, has decreased in recent years as the Company continues to buy back limited partner interests.

Regulation

Regulation of Transportation and Sale of Natural Gas:

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended ("NGA"), the Natural Gas Policy Act of 1978, as amended ("NGPA"), and regulations promulgated there under by the Federal Energy Regulatory Commission ("FERC") and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended (the "Decontrol Act"). The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, FERC issued Order No. 636 and a series of related orders (collectively, "Order No. 636") to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, FERC issued Order No. 637 and subsequent orders (collectively, "Order No. 637"), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 have been upheld on judicial review, and most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

The Outer Continental Shelf Lands Act ("OCSLA"), which FERC implements as to transportation and pipeline issues, requires that all pipelines operating on or across the outer continental shelf ("OCS") provide open access, non-discriminatory transportation service. One of FERC's principal goals in carrying out OCSLA's mandate is to increase transparency in the market to provide producers and shippers on the OCS with greater assurance of open access service on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines.

It should be noted that FERC currently is considering whether to reformulate its test for defining non-jurisdictional gathering in the shallow waters of the OCS and, if so, what form that new test should take. The stated purpose of this initiative is to devise an objective test that furthers the goals of the NGA by protecting producers from the unregulated market power of third-party transporters of gas, while providing incentives for investment in production, gathering and transportation infrastructure offshore. While we cannot predict whether FERC's gathering test ultimately will be revised and, if so, what form such revised test will take, any test that refunctionalizes as FERC-jurisdictional transmission facilities currently classified as gathering would impose an increased regulatory burden on the owner of those facilities by subjecting the facilities to NGA certificate and abandonment requirements and rate regulation.

We cannot accurately predict whether FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is materially different from the effect of such regulation on our competitors.

Regulation of Transportation of Oil:

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is materially different from the effect of such regulation on our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Production:

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and plugging and abandonment and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. Many states also restrict production to the market demand for oil and natural gas, and states have indicated interest in revising applicable regulations. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Some of our offshore operations are conducted on federal leases that are administered by Minerals Management Service ("MMS") and are required to comply with the regulations and orders promulgated by MMS under OCSLA. Among other things, we are required to obtain prior MMS approval for any exploration plans we pursue and our development and production plans for these leases. MMS regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under limited circumstances, MMS could require us to suspend or terminate our operations on a federal lease.

MMS also establishes the basis for royalty payments due under federal oil and natural gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and natural gas leases. The basis for royalty payments established by MMS and the state regulatory authorities is generally applicable to all federal and state oil and natural gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Taxation

The Company's oil and gas operations are affected by federal income tax laws applicable to the petroleum industry. The Company is permitted to deduct currently, rather than capitalize, intangible drilling and development costs incurred or borne by it. As an independent producer, the Company is also entitled to a deduction for percentage depletion with respect to the first 1,000 barrels per day of domestic crude oil (and/or equivalent units of domestic natural gas) produced by it, if such percentage depletion exceeds cost depletion. Generally, this deduction is computed based upon the lesser of 100% of the net income, or 15% of the gross income from a property, without reference to the basis in the property. The amount of the percentage depletion deduction so computed which may be deducted in any given year is limited to 65% of taxable income. Any percentage depletion deduction disallowed due to the 65% of taxable income test may be carried forward indefinitely.

See Notes 1 and 9 to the consolidated financial statements included in this Report for a discussion of accounting for income taxes and availability of federal tax net operating loss carryforwards and alternative minimum tax credit carryforwards.

Competition and Markets

The business of acquiring producing properties and non-producing leases suitable for exploration and development is highly competitive. Competitors of the Company, in its efforts to acquire both producing and non-producing properties, include oil and gas companies, independent concerns, income programs and individual producers and operators, many of which have financial resources, staffs and facilities substantially greater than those available to the Company. Furthermore, domestic producers of oil and gas must not only compete with each other in marketing their output, but must also compete with producers of imported oil and gas and alternative energy sources such as coal, nuclear power and hydroelectric power. Competition among petroleum companies for favorable oil and gas properties and leases can be expected to increase.

The availability of a ready market for any oil and gas produced by the Company at acceptable prices per unit of production will depend upon numerous factors beyond the control of the Company, including the extent of domestic production and importation of oil and gas, the proximity of the Company's producing properties to gas pipelines and the availability and capacity of such pipelines, the marketing of other competitive fuels, fluctuation in demand, governmental regulation of production, refining, transportation and sales, general national and worldwide economic conditions, and use and allocation of oil and gas and their substitute fuels. There is no assurance that the Company will be able to market all of the oil or gas produced by it or that favorable prices can be obtained for the oil and gas production.

Listed below are the percent of the Company's total oil and gas sales made to each of the customers whose purchases represented more than 10% of the Company's oil and gas sales.

Oil Purchasers:	
Texon Distributing L.P.	26.65%
Plains All American Inc.	29.29%
TEPPCO Crude Oil, L.L.C.	16.20%
LPC Crude Oil, Inc.	16.10%
Gas Purchasers:	
Unimark LLC	10.29%

Although there are no long-term purchasing agreements with these purchasers, the Company believes that they will continue to purchase its oil and gas products and, if not, could be replaced by other purchasers.

Environmental Matters

Various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), the Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), and the Federal Clean Air Act, as amended (the "Clean Air Act"), affect our operations and costs. In particular, our exploration, development and production operations, our activities in connection with storage and transportation of oil and other hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes may be subject to regulation under these and similar state legislation. These laws and regulations:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties or the imposition of injunctive relief. Changes in environmental laws and regulations occur regularly, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the oil and natural gas industry in general. While we believe 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, there is no assurance that this trend will continue in the future.

As with the industry generally, compliance with existing regulations increases our overall cost of business. The areas affected include:

- unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water;

- capital costs to drill exploration and development wells primarily related to the management and disposal of drilling fluids and other oil and natural gas exploration wastes; and

- capital costs to construct, maintain and upgrade equipment and facilities.

Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"). CERCLA, also known as "Superfund," imposes liability for response costs and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of a disposal site and entities that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our ordinary operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed.

We currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. These properties and wastes disposed on these properties may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators;

- to clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

At this time, we do not believe that we are associated with any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990, as amended (the "OPA"), and regulations there under impose liability on "responsible parties" for damages resulting from oil spills into or upon navigable waters, ad adjoining shorelines or in the exclusive economic zone of the United States. Liability under OPA is strict, and under certain circumstances joint and several, and potentially unlimited. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150.0 million depending on the risk represented by the quantity or quality of oil that is handled by the facility. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

U.S. Environmental Protection Agency. U.S. Environmental Protection Agency regulations address the disposal of oil and natural gas operational wastes under three federal acts more fully discussed in the paragraphs that follow. The Resource Conservation and Recovery Act of 1976, as amended ("RCRA"), provides a framework for the safe disposal of discarded materials and the management of solid and hazardous wastes. The direct disposal of operational wastes into offshore waters is also limited under the authority of the Clean Water Act. When injected underground, oil and natural gas wastes are regulated by the Underground Injection Control program under Safe Drinking Water Act. If wastes are classified as hazardous, they must be properly transported, using a uniform hazardous waste manifest, documented, and disposed at an approved hazardous waste facility. We have coverage under the Region VI National Production Discharge Elimination System Permit for discharges associated with exploration and development activities. We take the necessary steps to ensure all offshore discharges associated with a proposed operation, including produced waters, will be conducted in accordance with the permit.

Resource Conservation Recovery Act. RCRA is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

Clean Water Act. The Clean Water Act imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Safe Drinking Water Act. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. The Safe Drinking Water Act of 1974, as amended establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In Louisiana and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Marine Protected Areas. Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs")in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

Marine Mammal and Endangered Species. Federal Lease Stipulations address the reduction of potential taking of protected marine species (sea turtles, marine mammals, Gulf Sturgen and other listed marine species). MMS permit approvals will be conditioned on collection and removal of debris resulting from activities related to exploration, development and production of offshore leases. MMS has issued Notices to Lessees and Operators ("NTL") 2003-G06 advising of requirements for posting of signs in prominent places on all vessels and structures and of an observing training program.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including OCSLA, the National Environmental Policy Act ("NEPA"), and the Coastal Zone Management Act ("CZMA") require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior ("DOI") to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires DOI and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and, potentially, an environmental impact statement. CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and natural gas development. In obtaining various approvals from the DOI, we must certify that we will conduct our activities in a manner consistent with an applicable program.

Lead-Based Paints. Various pieces of equipment and structures owned by us may have been coated with lead-based paints as was customary in the industry at the time these pieces of equipment were fabricated and constructed. These paints may contain lead at a concentration high enough to be considered a regulated hazardous waste when removed. If we need to remove such paints in connection with maintenance or other activities and they qualify as a regulated hazardous waste, this would increase the cost of disposal. High lead levels in the paint might also require us to institute certain administrative and/or engineering controls required by the Occupational Safety and Health Act and MMS to ensure worker safety during paint removal.

Air Pollution Control. The Clean Air Act and state air pollution laws adopted to fulfill its mandates provide a framework for national, state and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Air emissions associated with offshore activities are projected using a matrix and formula supplied by MMS, which has primacy from the Environmental Protection Agency for regulating such emissions.

Naturally Occurring Radioactive Materials ("NORM"). NORM are materials not covered by the Atomic Energy Act, whose radioactivity is enhanced by technological processing such as mineral extraction or processing through exploration and production conducted by the oil and natural gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards established by the states, as applicable.

Employees

At March 25, 2005, the Company had 190 full-time and 6 part-time employees, 16 of whom were employed by the Company at its principal offices in Stamford, Connecticut, 20 in Houston, Texas, at the offices of Prime Operating Company, Eastern Oil Well Service Company, EOWS Midland Company and F-W Oil Exploration L.L.C., and 160 employees who were primarily involved in the district operations of the Company in Houston and Midland, Texas, Oklahoma City, Oklahoma and Charleston, West Virginia.

Item 2. PROPERTIES.

The Company's executive offices are located in leased premises at One Landmark Square, Stamford, Connecticut. The executive offices of Prime Operating Company, Eastern Oil Well Service Company, EOWS Midland Company and F-W Oil Exploration L.L.C. are located in leased premises in Houston, Texas, and the offices of Southwest Oilfield Construction Company are in Oklahoma City, Oklahoma.

The Company maintains district offices in Houston and Midland, Texas, Oklahoma City, Oklahoma and Charleston, West Virginia, and has field offices in Carrizo Springs and Midland, Texas, Kingfisher and Garvin, Oklahoma and Orma, West Virginia.

Substantially all of the Company's oil and gas properties are subject to a mortgage given to collateralize indebtedness of the Company, or are subject to being mortgaged upon request by the Company's lender for additional collateral.

The information set forth below concerning the Company's properties, activities, and oil and gas reserves include the Company's interests in affiliated entities.

The following table sets forth the exploratory and development drilling experience with respect to wells in which the Company participated during the five years ended December 31, 2004.

	2004		2003		2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory:										
Oil	2	.400	—	—	1	1	1	1.000	—	—
Gas	10	2.850	4	1.565	1	.25	1	.602	3	1.279
Dry	4	1.594	6	1.400	4	2.50	—	—	2	.276
Development:										
Oil	—	—	6	2.561	2	1.25	1	.500	—	—
Gas	7	3.993	8	4.478	10	7.59	7	4.926	7	4.134
Dry	2	1.594	1	.500	6	5.30	2	1.585	—	—
Total:										
Oil	2	.400	6	2.56	3	2.25	2	1.500	—	—
Gas	17	6.843	12	6.042	11	7.84	8	5.528	10	5.413
Dry	6	2.722	7	1.900	10	7.80	2	1.585	2	.276
	25	9.965	25	10.504	24	17.89	12	8.613	12	5.689

Oil and Gas Production

As of December 31, 2004, the Company had ownership interests in the following numbers of gross and net producing oil and gas wells and gross and net producing acres (1).

	Gross	Net
Producing wells (1)		
Oil Wells	851	320.99
Gas Wells	1,149	399.47
Producing Acres	263,841	92,539

(1) A gross well or gross acre is a well or an acre in which a working interest is owned. A net well or net is the sum of the fractional revenue interests owned in gross wells or gross acres. Wells are classified by their primary product. Some wells produce both oil and gas.

The following table shows the Company's net production of crude oil and natural gas for each of the five years ended December 31, 2004. "Net" production is net after royalty interests of others are deducted and is determined by multiplying the gross production volume of properties in which the Company has an interest by percentage of the leasehold, mineral or royalty interest owned by the Company.

	2004	2003	2002	2001	2000
Oil (barrels)	371,000	370,000	321,000	306,000	298,000
Gas (Mcf)	5,138,000	3,991,000	3,540,000	3,764,000	3,930,000

The following table sets forth the Company's average sales price per barrel of crude oil and average sales prices per one thousand cubic feet ("Mcf") of gas, together with the Company's average production costs per unit of production for the five years ended December 31, 2004.

	2004	2003	2002	2001	2000
Average sales price per barrel	$ 40.45	28.90	23.37	24.92	28.34
Average sales price Per Mcf	$ 5.64	4.80	3.06	4.08	3.76
Average production costs per net equivalent barrel (1)	$ 12.17	12.42	11.80	11.88	9.57

(1) Net equivalent barrels are computed at a rate of 6 Mcf per barrel.

Undeveloped Acreage

The following table sets forth the approximate gross and net undeveloped acreage in which the Company has leasehold, mineral and royalty interests as of December 31, 2004. "Undeveloped acreage" is that acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

	Leasehold Interests		Mineral Interests		Royalty Interests	
State	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Colorado			799	23		
Gulf of Mexico	95,225	54,489				
Montana			13,984	59	786	5
Nebraska			2,553	331		
North Dakota			640	1		
Oklahoma	5,011	2,938	320	1		
Texas	18,838	8,518	680	16		
Wyoming	1,000	125	5,043	35	14	35
TOTAL	120,074	66,070	24,019	466	926	40

Reserves

The Company's interests in proved developed and undeveloped oil and gas properties have been evaluated by Ryder Scott Company, L.P. for each of the five years ended December 31, 2004. All of the Company's reserves are located within the continental United States. The following table summarizes the Company's oil and gas reserves at each of the respective dates (figures rounded):

	Reserve Category					
	Proved Developed		Proved Undeveloped		Total	
As of 12-31	Oil (bbls)	Gas (Mcf)	Oil (bbls)	Gas (Mcf)	Oil (bbls)	Gas (Mcf)
2000	2,362,000	27,029,000	-	-	2,362,000	27,029,000
2001	1,996,000	24,266,000	-	453,000	1,996,000	24,719,000
2002	2,319,000	29,917,000	-	-	2,319,000	29,917,000
2003	2,865,000	34,045,000	40,000	4,960,000	2,905,000	39,005,000
2004	2,926,000	37,728,000	6,000	7,142,000	2,932,000	44,870,000

The estimated future net revenue (using current prices and costs as of those dates, exclusive of income taxes) and the present value of future net revenue (at a 10% discount for estimated timing of cash flow) for the Company's proved developed and proved undeveloped oil and gas reserves at the end of each of the five years ended December 31, 2004, are summarized as follows (figures rounded):

	Proved Developed		Proved Undeveloped		Total	
As of 12-31	Future Net Revenue	Present Value Of Future Net Revenue	Future Net Revenue	Present Value Of Future Net Revenue	Future Net Revenue	Present Value Of Future Net Revenue
2000	$ 199,376,000	113,137,000	-	-	199,376,000	113,137,000
2001	$ 41,086,000	24,653,000	957,000	629,000	42,043,000	25,282,000
2002	$ 97,600,000	56,855,000	-	-	97,600,000	56,855,000
2003	$ 141,194,000	85,695,000	22,891,000	17,401,000	164,085,000	103,096,000
2004	$ 177,916,000	107,116,000	33,484,000	26,796,000	211,400,000	133,912,000

"Proved developed" oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. "Proved undeveloped" oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

In accordance with FASB Statement No. 69, December 31 market prices are determined using the daily oil price or daily gas sales price ("spot price") adjusted for oilfield or gas gathering hub and wellhead price differentials (e.g. grade, transportation, gravity, sulfur, and BS&W) as appropriate. Also in accordance with SEC and FASB specifications, changes in market prices subsequent to December 31 are not considered.

The spot price for gas at December 31, 2004 and 2003 was $6.18 and $5.97 per MMBTU, respectively. The range of spot prices during the year 2004 was a low of $4.39 and a high of $7.96 and the average was $5.87. The range during the first quarter of 2005 has been from $5.56 to $7.19 with an average of $6.38. The recent futures market prices have traded above $7.00 per MMBTU.

The NYMEX price for oil at December 31, 2004 and 2003 was $43.45 and $32.55 per barrel, respectively. The range of NYMEX prices during the year 2004 was a low of $32.48 and a high of $55.17 and the average was $41.31. Range during the first quarter of 2005 has been from $42.12 to $56.72 with an average of $49.79. The recent futures market prices have fluctuated around $54.00.

While it may reasonably be anticipated that the prices received by the Company for the sale of its production may be higher or lower than the prices used in this evaluation, as described above, and the operating costs relating to such production may also increase or decrease from existing levels, such possible changes in prices and costs were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation for the SEC case. Actual volumes produced, prices received and costs incurred by the Company may vary significantly from the SEC case.

Since January 1, 2005, the Company has not filed any estimates of its oil and gas reserves with, nor were any such estimates included in any reports to, any federal authority or agency, other than the Securities and Exchange Commission, except Form EIA-23, Annual Survey of Domestic Oil and Gas Reserves, filed with The Energy Information Administration of the U.S. Department of Energy.

Item 3. LEGAL PROCEEDINGS.

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

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

No matters were submitted during the fourth quarter of the fiscal year ended December 31, 2004 to a vote of the Company's security-holders through the solicitation of proxies or otherwise.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

The Company's Common Stock is traded in the NASDAQ Stock Market, trading symbol "PNRG". The high and low bid quotations for each quarterly period during the two years ended December 31, 2004, were as follows:

2004	High	Low	2003	High	Low
First Quarter...........	$ 15.15	$ 15.05	First Quarter..........	$ 9.43	$ 8.00
Second Quarter......	$ 18.16	$ 17.91	Second Quarter.....	$ 9.70	$ 8.05
Third Quarter.........	$ 19.21	$ 19.06	Third Quarter........	$ 10.56	$ 9.50
Fourth Quarter.......	$ 19.64	$ 18.61	Fourth Quarter......	$ 14.61	$ 9.43

The above quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

The number of record holders of the Company's Common Stock as of March 25, 2005 was 976.

No dividends have been declared or paid during the past two years on the Company's Common Stock. Provisions of the Company's line of credit agreement restrict the Company's ability to pay dividends. Such dividends may be declared out of funds legally available therefore, when and as declared by the Company's Board of Directors.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

2004 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Plan (1)
January	—	—	478,271
February	15,630	$ 15.39	462,641
March	3,500	$ 14.56	459,141
April	8,992	$ 17.01	450,149
May	15,874	$ 18.08	434,275
June	4,794	$ 18.09	429,481
July	35,952	$ 18.12	393,529
August	2,885	$ 18.09	390,644
September	340	$ 18.11	390,304
October	10,600	$ 18.48	379,704
November	12,438	$ 19.56	367,266
December	25,972	$ 19.51	341,294
Total/Average	136,977	$ 18.06	

(1) In December 1993, we announced that our Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of our common stock from time-to-time, in open market transactions or negotiated sales. A total of 2,400,000 shares have been authorized, to date, under this program. Through December 31, 2004 we repurchased a total of 2,058,706 shares under this program for $12,929,848 at an average price of $6.28 per share. Additional purchases of shares may occur as market conditions warrant. We expect future purchases will be funded with internally generated cash flow or from working capital.

Item 6. SELECTED FINANCIAL DATA

The following table summarizes certain selected financial data to highlight significant trends in the Company's financial condition and results of operations for the periods indicated. The selected financial data should be read in conjunction with the Financial Statements and related notes included elsewhere in this Report.

		2004	2003	2002	2001	2000
Revenues	$	62,428,000	46,719,000	34,186,000	42,408,000	39,182,000
Income from operations	$	10,223,000	8,047,000	2,168,000	6,968,000	6,148,000
Net income	$	7,275,000	5,702,000	1,757,000	5,413,000	5,365,000
Income per common share	$	2.04	1.56	0.47	1.39	1.26
Diluted net income per common share	$	1.70	1.31	0.40	1.18	1.08
Net cash provided by operations	$	26,995,000	19,622,000	9,644,000	12,313,000	11,498,000
Total assets	$	69,926,000	58,255,000	44,887,000	35,816,000	35,094,000
Long-term obligations	$	30,290,000	26,925,000	23,734,000	16,958,000	18,213,000
Cash dividends		None	None	None	None	None

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

This discussion should be read in conjunction with the financial statements of the Company and notes thereto. The Company's subsidiaries are defined in Note 1 of the financial statements.

Liquidity And Capital Resources:

Cash flow provided by operations for the year ended December 31, 2004, increased by $5 million, compared to the prior year, primarily due to a 18.5% increase in production and an increase in oil and gas prices throughout the entire year, combined with changes in our working capital accounts. We expect sufficient cash flow to be provided by operations during 2005 because of higher projected production from new properties, combined with oil and gas prices consistent with 2004 and steady operating, general and administrative, interest and financing costs.

Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but may be curtailed due to factors beyond our control. Hurricanes in the Gulf of Mexico may shut down our production for the duration of the storm's presence in the Gulf or damage production facilities so that we cannot produce from a particular property for an extended amount of time. In addition, downstream activities on major pipelines in the Gulf of Mexico can also cause us to shut-in production for various lengths of time.

Our realized oil and gas prices vary due to world political events, supply and demand of products, product storage levels, and weather patterns. We sell the vast majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility we sometimes lock in prices for some portion of our production through the use of financial instruments. Currently we have no such arrangements in place.

We expect to continue to make significant capital expenditures over the next several years as part of our long-term growth strategy. We have budgeted $25 million for drilling expenditures in 2005. We project that we will spend $10 million in the Gulf of Mexico and $15 million on onshore wells. In addition, we have committed approximately $16 million for offshore pipelines and production facilities.

If our exploratory drilling results in significant new discoveries, we will have to expend additional capital in order to finance the completion, development, and potential additional opportunities generated by our success. We believe that, because of the additional reserves resulting from the success and our record of reserve growth in recent years, we will be able to access sufficient additional capital through additional bank financing.

The Company has in place both a stock repurchase program and a limited partnership interest repurchase program. Spending under these programs in 2004 was $4.5 million. The Company expects to expend a similar amount in 2005.

Effective March 2005, we agreed with our lenders to increase the Company's borrowing base to $41,000,000. As of March 31, 2005, $21,500,000 was borrowed under the facility. The banks review the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a redetermined estimate of proved oil and gas reserves. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial covenants defined in the agreement. We are currently in compliance with these financial covenants. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable.

It is the goal of the Company to increase its oil and gas reserves and production through the acquisition and development of oil and gas properties. The Company also continues to explore and consider opportunities to further expand its oilfield servicing revenues through additional investment in field service equipment. However, the majority of the Company's capital spending is discretionary, and the ultimate level of expenditures will be dependent on the Company's assessment of the oil and gas business environment, the number and quality of oil and gas prospects available, the market for oilfield services, and oil and gas business opportunities in general.

Results of Operations:

2004 as compared to 2003

The Company had net income of $7,275,000 in 2004 as compared to $5,702,000 in 2003.

Oil and gas sales were $ 43,967,000 in 2004 as compared to $29,855,000 in 2003. A chart summarizing oil and gas production and revenue is presented below.

	2004	2003	Increase (Decrease)
Barrels of Oil Produced	371,000	370,000	1,000
Average Price Received	$ 40.45	$ 28.90	$ 11.55
Oil Revenue	$ 15,006,000	$ 10,693,000	$ 4,313,000
Mcf of Gas Produced	5,138,000	3,991,000	1,147,000
Average Price Received	$ 5.64	$ 4.80	$ 0.84
Gas Revenue	$ 28,961,000	$ 19,162,000	$ 9,799,000
Total Oil & Gas Revenue	$ 43,967,000	$ 29,855,000	$ 14,112,000

Field Service Revenue increased 9% to $11,965,000 in 2004 from $11,013,000 in 2003. This increase reflects higher utilization of equipment during 2004 combined with an upward trend in rates during the fourth quarter of 2004.

Lease operating expenses increased by 17% to $14,939,000 in 2004 as compared to $12,783,000 in 2003. The difference is attributable to production taxes related to higher prices combined with costs on properties added during 2004 and repairs made to marginal wells currently economic due to higher product price levels.

General and administrative expenses increased to $7,536,000 in 2004 as compared to $6,995,000 in 2003. This increase reflects the addition of FW's costs for the full year and increased ownership in the Partnerships.

Depreciation and depletion of oil and gas properties increased to $11,021,000 in 2004 from $6,283,000 in 2003. This increase is related to the additional capital expended during 2003 and 2004 combined with increased production.

Exploration costs in 2004 of $5,499,000 consist of dry hole expenditures and certain geological, geophysical and seismic costs. Dry hole costs of $4,656,000 during 2004 were attributable to the drilling of one offshore well and three wells onshore. Exploration costs of $519,000 were incurred during 2003 drilling seven dry holes.

Interest expense increased to $1,136,000 in 2004 from $880,000 in 2003 due to increased average outstanding debt. The average interest rates paid on outstanding borrowings during 2004 and 2003 were 3.91% and 3.84%, respectively. As of December 31, 2004 and 2003, the total outstanding borrowings were $29,900,000 and $27,280,000, respectively.

Income tax expense of $3,023,000 in 2004 represents a 29% effective rate as compared to the effective rate of 30% in 2003. Current tax expense in 2004 was $453,000 with the remainder being attributable to an increase in the Company's deferred tax liability.

The primary reason that the Company's federal tax expense for 2004 is well below the statutory rate is that the Company is allowed to deduct currently, rather than capitalize, intangible drilling costs as incurred. The current deduction of these costs, which are capitalized for financial accounting purposes, is also the primary reason for the increase in the Company's deferred tax liability between 2003 and 2004.

2003 as compared to 2002

The Company had net income of $5,702,000 in 2003 as compared to $1,757,000 in 2002.

Oil and gas sales were $29,855,000 in 2003 as compared to $18,330,000 in 2002. A chart summarizing oil and gas production and revenue is presented below.

	2003	2002	Increase (Decrease)
Barrels of Oil Produced	370,000	321,000	49,000
Average Price Received	$ 28.90	$ 23.37	$ 5.53
Oil Revenue	$ 10,693,000	$ 7,510,000	$ 3,183,000
Mcf of Gas Produced	3,991,000	3,540,000	451,000
Average Price Received	$ 4.80	$ 3.06	$ 1.74
Gas Revenue	$ 19,162,000	$ 10,820,000	$ 8,342,000
Total Oil & Gas Revenue	$ 29,855,000	$ 18,330,000	$ 11,525,000

Field Service Revenue increased to $11,013,000 in 2003 from $9,891,000 in 2002. This increase reflects higher utilization of equipment during 2003.

Lease operating expenses increased by 25% to $12,783,000 in 2003 as compared to $10,210,000 in 2002. The difference is attributable to production taxes related to higher prices combined with costs on properties added during 2003 and repairs made to marginal wells currently economic due to higher product price levels.

General and administrative expenses increased to $6,995,000 in 2003 as compared to $6,007,000 in 2002 . This increase reflects the addition of FW's costs and increased ownership in the Partnerships offset by savings related to reduced personnel costs in the Connecticut office.

Depreciation and depletion of oil and gas properties increased by 57% to $6,283,000 in 2003 from $3,988,000 in 2002. This increase is related to the additional capital costs expended in 2003 combined with increased production.

Exploration costs of $519,000 were incurred during 2003 drilling seven dry holes. Exploration costs of $894,000 were incurred during 2002 drilling five dry holes.

Interest expense increased to $880,000 in 2003 from $766,000 in 2002 due to increased average outstanding debt. The average interest rates paid on outstanding borrowings subject to interest at the bank's base rate during 2003 and 2002 were 4.50%. During the same periods, the average rates paid on outstanding borrowings bearing interest based upon the LIBO rate were 3.84% and 3.59%. As of December 31, 2003 and 2002, the total outstanding borrowings were $27,280,000 and $24,500,000, respectively.

Income tax expense of $2,446,000 in 2003 represents a 30% effective rate as compared to the effective rate of 20% in 2002. Current tax expense in 2003 was $867,000 with the remainder being attributable to an increase in the Company's deferred tax liability.

The primary reason that the Company's federal tax expense for 2003 is well below the statutory rate is that the Company is allowed to deduct currently, rather than capitalize, intangible drilling costs as incurred. The current deduction of these costs, which are capitalized for financial accounting purposes, is also the primary reason for the increase in the Company's deferred tax liability between 2002 and 2003.

Item 7a. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The Company is exposed to interest rate risk on its line of credit, which has variable rates based upon the lenders base rate, as defined, and the London Inter-Bank Offered rate. Based on the balance outstanding at December 31, 2004 a hypothetical 2.5% increase in the applicable interest rates would increase interest expense by approximately $727,000.

Oil and gas prices have historically been extremely volatile, and have been particularly so in recent years. The Company did not enter into significant hedging transactions during 2004, and had no open hedging transactions at December 31, 2004. Declines in domestic oil and gas prices could have a material adverse effect on the Company's revenues, operating results, estimates of economically recoverable reserves and the net revenue therefrom.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The financial statements and supplementary information included in this Report are described in the Index to Financial statements at Page F-1 of this Report.

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

None.

Item 9A. INTERNAL CONTROLS AND PROCEDURES.

(a) Evaluation of disclosure controls and procedures.

Our management, with the participation of our chief executive officer and chief financial officer, evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934 as of the end of the period covered by this Annual Report on Form 10-K. The evaluation included certain internal control areas in which we have made and are continuing to make changes to improve and enhance controls. In designing and evaluating the disclosure controls and procedures, management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs.

Based on that evaluation, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting.

There were no changes in our internal control over financial reporting that occurred during the period covered by this Annual Report on Form 10-K that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management is currently in the process of comprehensively documenting and further analyzing our system of internal control over financial reporting. We are in the process of designing enhanced processes and controls to address any issues identified through this review. We plan to continue this initiative as well as prepare for our first management report on internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002 for the annual period ending December 31, 2006, which may result in changes to our internal control over financial reporting.

Item 9B. OTHER INFORMATION.

No information was required to be disclosed by Registrant in a report on Form 8-K during the fourth quarter of the year covered by this Report.

PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

Information relating to the Company's Directors, nominees for Directors and executive officers is included in the Company's definitive proxy statement relating the Company's Annual Meeting of Stockholders to be held in June, 2005, which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2004 and which is incorporated herein by reference.

Item 11. EXECUTIVE COMPENSATION.

Information relating to executive compensation is included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June, 2005, which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2004 and which is incorporated herein by reference.

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

Information relating to security ownership of certain beneficial owners and management is included in the Company's definitive proxy statement relating the Company's Annual Meeting of Stockholders to be held in June, 2005 which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2004 and which is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS.

Information relating to certain transactions by Directors and executive officers of the Company is included in the Company's definitive proxy statement relating the Company's Annual Meeting of Stockholders to be held in June, 2005, which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2004 and which is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Information relating to principal accountant fees and services is included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June, 2005, which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2004 and which is incorporated herein by reference.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this Report:

1. Financial statements (Index to Financial Statements at page F-1 of this Report)

2. Financial Statement Schedules (Index to Financial Statements – Supplementary Information)

3. Exhibits

3.1 Restated Certificate of Incorporation of PrimeEnergy Corporation (filed herewith)

3.2 Bylaws of PrimeEnergy Corporation (filed herewith)

10.3.1 Adoption Agreement #003 dated 4/23/2002, MassMutual Life Insurance Company Flexinvest Prototype Non-Standardized 401(k) Profit-Sharing Plan; EGTRRA Amendment to the PrimeEnergy employees 401(k) Savings Plan; MassMutual Retirement Services Flexinvest Defined ContributionPrototype Plan; Protected Benefit Addendum; Addendum to the Administrative Services Agreement Loan Agreement; Addendum to Administrative Services Agreement GUST Restatement Provisions; General Trust Agreement (Incorporated by reference to Exhibit 10.3.1of PrimeEnergy Corporation form 10-K for the year ended December 31,2002) (1)

10.18 Composite copy of Non-Statutory Option Agreements (filed herewith)

10.22 Credit Agreement dated as of December 19, 2002 between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank , FSB (incorporated by reference to Exhibit 10.22 of PrimeEnergy Corporation 10-K for the year ended December 31, 2002)

10.22.1 First Amendment to Credit Agreement effective as of June 1, 2003 between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank , FSB (Incorporated by reference to Exhibit 10.22.1 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2003)

10.22.2 Second Amendment to Credit Agreement effective as of September 22,2003 between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company, F-W Oil Exploration Company L.L.C. and Guaranty Bank , FSB (Incorporated by reference to exhibit 10.2.2 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2003)

10.22.3 Third Amendment to Credit Agreement effective as of February 17, 2004, between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company, F-W Oil Exploration Company, L.L.C. and Guaranty Bank, FSB (filed herewith)

10.22.4 Fourth Amendment to Credit Agreement effective as of December 28, 2004, between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank, FSB (filed herewith)

10.23 Mortgage, Deed of Trust, Security Agreement, Financing Statement and Assignment of Production from PrimeEnergy Corporation and PrimeEnergy Management Corporation for the benefit of Guaranty Bank, FSB (Incorporated by reference to Exhibit 10.23 of PrimeEnergy Corporation 10-K for the year ended December 31, 2002)

10.23.1 Mortgage, Deed of Trust, Security Agreement, Financing Statements and Assignment of Production effective as of September 22, 2003, by and among F-W Oil Exploration L.L.C., PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company for benefit of Guaranty Bank, FSB (Incorporated by reference to exhibit 10.23.1 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2003)

10.24 Act of Mortgage and Security Agreement, by PrimeEnergy Corporation and PrimeEnergy Management Corporation to Guaranty Bank, FSB (Incorporated by reference to Exhibit 10.24 of PrimeEnergy Corporation 10-K for the year ended December 31, 2002)

10.25 Credit Agreement dated December 28, 2004, between F-W Oil Exploration L.L.C. and Guaranty Bank, FSB (filed herewith)

10.26.1 Security Agreement dated December 28, 2004, between F-W Oil Exploration L.L. C. and Guaranty Bank, FSB (filed herewith)

10.26.2 Ratification of and Amendment to Act of Mortgage and Security Agreement effective December 28, 2004,by F-W Oil Exploration L.L.C. for the benefit of Guaranty Bank, FSB (filed herewith)

10.26.3 Ratification of and Amendment to Mortgage, Deed of Trust, Security Agreement, Financing

Statement, Fixture Filing and Assignment of Production by F-W Oil Exploration L.L.C. for the benefit of Guaranty Bank, FSB (filed herewith)

21	Subsidiaries (filed herewith)
23	Consent of Ryder Scott & Company L.P. Company (filed herewith)
31.1	Certification of Chief Executive Officer pursuant to Rule13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith)
31.2	Certification of Chief Financial Officer pursuant to Rule13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith)
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith)
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith)

SIGNATURES

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, on the 31st day of March, 2005.

PrimeEnergy Corporation

By: /s/ CHARLES E. DRIMAL, JR.
Charles E. Drimal, Jr.
President

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 indicated and on the 31st day of March, 2005.

/s/ CHARLES E. DRIMAL, JR. Charles E. Drimal, Jr.	Director and President; The Principal Executive Officer		
/s/ BEVERLY A. CUMMINGS Beverly A. Cummings	Director, Vice President and Treasurer; The Principal Financial and Accounting Officer		
/s/ MATTHIAS ECKENSTEIN Matthias Eckenstein	Director	/s/ CLINT HURT Clint Hurt	Director
/s/ H. GIFFORD FONG H. Gifford Fong	Director	/s/ JAN K. SMEETS Jan K. Smeets	Director
/s/ THOMAS S.T. GIMBEL Thomas S.T. Gimbel	Director	/s/ GAINES WEHRLE Gaines Wehrle	Director

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INDEX TO FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
PrimeEnergy Corporation and Subsidiaries:

We have audited the accompanying consolidated balance sheets of PrimeEnergy Corporation and Subsidiaries (the Corporation) as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31 2004, 2003 and 2002. These financial statements are the responsibility of the Corporation'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 PrimeEnergy Corporation and Subsidiaries as of December 31, 2004 and 2003, and the consolidated results of its operations and cash flows for the years ended December 31, 2004, 2003 and 2002 in conformity with U.S generally accepted accounting principles.

PUSTORINO, PUGLISI & CO., LLP
New York, New York
March 30, 2005

PRIMEENERGY CORPORATION and SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS, December 31, 2004 and 2003

	2004	2003
ASSETS:		
Current assets:		
Cash and cash equivalents	$ 6,476,000	$ 3,891,000
Restricted cash and cash equivalents	1,864,000	1,479,000
Accounts receivable, net	8,694,000	7,108,000
Due from related parties	—	209,000
Prepaid expenses	447,000	336,000
Other current assets	433,000	297,000
Deferred income taxes	409,000	374,000
Total current assets	18,323,000	13,694,000
Property and equipment, at cost:		
Proved oil and gas properties at cost	95,018,000	91,012,000
Unproved oil and gas properties at cost	13,149,000	3,091,000
Less, accumulated depletion and depreciation	(60,098,000)	(53,196,000)
	48,069,000	40,907,000
Field and office equipment	9,610,000	9,389,000
Less, accumulated depreciation	(6,307,000)	(5,964,000)
	3,303,000	3,425,000
Total net property and equipment	51,372,000	44,332,000
Other assets	231,000	229,000
Total assets	$ 69,926,000	$ 58,255,000

The accompanying notes are an integral part of the consolidated financial statements.

PRIMEENERGY CORPORATION and SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS, December 31, 2004 and 2003

	2004	2003
LIABILITIES and STOCKHOLDERS' EQUITY:		
Current liabilities:		
Accounts payable	$ 9,929,000	$ 8,528,000
Current portion of other long-term obligations	12,000	692,000
Accrued liabilities:		
Payroll, Benefits, Interest and Other	3,228,000	3,504,000
Due to related parties	600,000	933,000
Total current liabilities	13,769,000	13,657,000
Long-term bank debt	29,900,000	26,613,000
Other long-term obligations	—	12,000
Asset retirement obligations	390,000	300,000
Deferred income taxes	7,630,000	4,237,000
Total liabilities	51,689,000	44,819,000
Stockholders' equity:		
Preferred stock, $.10 par value, authorized 5,000,000 shares; none issued	—	—
Common stock, $.10 par value, authorized 10,000,000 shares; issued 7,694,970 in 2004 and 2003	769,000	769,000
Paid in capital	11,024,000	11,024,000
Retained earnings	22,653,000	15,378,000
	34,446,000	27,171,000
Treasury stock, at cost 4,202,745 common shares in 2004 and 4,065,768 in 2003	(16,209,000)	(13,735,000)
Total stockholders' equity	18,237,000	13,436,000
Total liabilities and stockholders' equity	$ 69,926,000	$ 58,255,000

The accompanying notes are an integral part of the consolidated financial statements.

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS of OPERATIONS

for the years ended December 31, 2004, 2003 and 2002

	2004	2003	2002
Revenue:			
Oil and gas sales	$ 43,967,000	$ 29,855,000	$ 18,330,000
Field service revenue	11,965,000	11,013,000	9,891,000
Administrative overhead fees	6,317,000	5,723,000	5,588,000
Gains/(losses) on derivative instruments net	—	(52,000)	(113,000)
Interest and other income	179,000	180,000	490,000
	62,428,000	46,719,000	34,186,000
Costs and expenses:			
Lease operating expense	14,939,000	12,783,000	10,210,000
Field service expense	10,939,000	9,970,000	8,910,000
Depreciation, depletion and amortization	12,156,000	7,525,000	5,231,000
General and administrative expense	7,536,000	6,995,000	6,007,000
Exploration costs	5,499,000	519,000	894,000
Interest expense	1,136,000	880,000	766,000
	52,205,000	38,672,000	32,018,000
Income from operations	10,223,000	8,047,000	2,168,000
Other income:			
Gain on sale and exchange of assets	75,000	101,000	32,000
Income before provision for income taxes	10,298,000	8,148,000	2,200,000
Provision for income taxes	3,023,000	2,446,000	443,000
Net income	$ 7,275,000	$ 5,702,000	$ 1,757,000
Basic net income per common share	$ 2.04	$ 1.56	$ 0.47
Diluted net income per common share	$ 1.70	$ 1.31	$ 0.40

The accompanying notes are an integral part of the consolidated financial statements.

PRIMEENERGY CORPORATION and SUBSIDIARIES

CONSOLIDATED STATEMENT of STOCKHOLDERS' EQUITY

for the years ended December 31, 2004, 2003 and 2002

	Common Stock Shares	Common Stock Amount	Additional Paid In Capital	Retained Earnings	Treasury Stock	Total
Balance at December 31, 2001	7,694,970	$ 769,000	$ 11,024,000	$ 7,919,000	$ (12,349,000)	$ 7,363,000
Purchased 92,862 shares of common stock					(745,000)	(745,000)
Net income				1,757,000		1,757,000
Balance at December 31, 2002	7,694,970	$ 769,000	$ 11,024,000	$ 9,676,000	$ (13,094,000)	$ 8,375,000
Purchased 63,804 shares of common stock					(641,000)	(641,000)
Net income				5,702,000		5,702,000
Balance at December 31, 2003	7,694,970	$ 769,000	$ 11,024,000	$ 15,378,000	$ (13,735,000)	$ 13,436,000
Purchased 136,977 shares of common stock					(2,474,000)	(2,474,000)
Net income				7,275,000		7,275,000
Balance at December 31, 2004	7,694,970	$ 769,000	$ 11,024,000	$ 22,653,000	$ (16,209,000)	$ 18,237,000

The accompanying notes are an integral part of the consolidated financial statements.

PRIMEENERGY CORPORATION and SUBSIDIARIES

CONSOLIDATED STATEMENT of CASH FLOWS

for the years ended December 31, 2004, 2003 and 2002

	2004	2003	2002
Cash flows from operating activities:			
Net income	$ 7,275,000	$ 5,702,000	$ 1,757,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	12,156,000	7,525,000	5,231,000
Dry hole and abandonment costs	5,499,000	519,000	894,000
Gain on sale of properties	(75,000)	(101,000)	(32,000)
Provision for deferred income taxes	3,358,000	1,580,000	243,000
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(1,586,000)	(2,982,000)	(328,000)
(Increase) decrease in due from related parties	209,000	4,562,000	153,000
(Increase) decrease in other assets	(137,000)	3,000	682,000
(Increase) decrease in prepaid expenses	(111,000)	(97,000)	(175,000)
Increase (decrease) in accounts payable	1,016,000	1,699,000	736,000
Increase (decrease) in accrued liabilities	(276,000)	1,712,000	(19,000)
Increase (decrease) in due to related parties	(333,000)	(500,000)	502,000
Net cash provided by operating activities	26,995,000	19,622,000	9,644,000
Cash flows from investing activities			
Proceeds from sale of properties and equipment	75,000	101,000	32,000
Additions to property and equipment	(24,696,000)	(19,835,000)	(14,442,000)
Net cash used in investing activities	(24,621,000)	(19,734,000)	(14,410,000)
Cash flows from financing activities			
Purchase of stock for treasury	(2,474,000)	(641,000)	(745,000)
Repayment of long-term bank debt and other long-term obligations	(29,837,000)	(43,679,000)	(43,260,000)
Increase in long-term bank debt and other long-term obligations	32,522,000	46,437,000	50,572,000
Net cash provided by (used in) financing activities	211,000	2,117,000	6,567,000
Net increase (decrease) in cash	2,585,000	2,005,000	1,801,000
Cash and cash equivalents, beginning of year	3,891,000	1,886,000	85,000
Cash and cash equivalents, end of year	$ 6,476,000	$ 3,891,000	$ 1,886,000
Supplemental disclosures:			
Income taxes paid during the year	$ —	$ 83,500	$ —
Net income tax refunds received during the year	$ 172,000	$ —	$ 745,000
Interest paid during the year	$ 953,000	$ 880,000	$ 766,000

Supplemental information of noncash investing and financing activities:

In 2002, the Company recorded capital lease obligations in the amount of $59,000.

The accompanying notes are an integral part of the consolidated financial statements.

1. Description of Operations and Significant Accounting Policies

Nature of Operations:

PrimeEnergy Corporation ("PEC"), a Delaware corporation, was organized in March 1973. The Company is engaged in the development, acquisition and production of oil and natural gas properties. The Company owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the United States, including Colorado, Kansas, Louisiana, Mississippi, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, Texas, Utah, West Virginia and Wyoming and the Gulf of Mexico. The Company operates 1,533 wells and owns non-operating interests in over 770 additional wells. Additionally, the Company provides well-servicing support operations, site-preparation and construction services for oil and gas drilling and reworking operations, both in connection with the Company's activities and providing contract services for third parties. The Company is publicly traded on the NASDAQ under the symbol "PNRG".

PEC owns Eastern Oil Well Service Company ("EOWSC"), EOWS Midland Company ("EMID") and Southwest Oilfield Construction Company ("SOCC"), all of which perform oil and gas field servicing. PEC also owns Prime Operating Company ("POC"), which serves as operator for most of the producing oil and gas properties owned by the Company and affiliated entities. During 2003 PEC acquired a sixty percent interest in F-W Oil Exploration LLC, ("FW"), which owns and operates properties in the Gulf of Mexico. PrimeEnergy Corporation and its subsidiaries are herein referred to as the "Company." PrimeEnergy Management Corporation ("PEMC"), a wholly-owned subsidiary, acts as the managing general partner, providing administration, accounting and tax preparation services for 18 private and publicly-held limited partnerships and 2 trusts (collectively, the "Partnerships"). During the course of 2003 PrimeEnergy dissolved 20 private limited partnerships.

The markets for the Company's products are highly competitive, as oil and gas are commodity products and prices depend upon numerous factors beyond the control of the Company, such as economic, political and regulatory developments and competition from alternative energy sources.

Consolidation and Presentation:

The consolidated financial statements include the accounts of PrimeEnergy Corporation, its subsidiaries and the Partnerships, using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenue and expenses are included in the appropriate classifications in the consolidated financial statements. Inter-company balances and transactions are eliminated in preparing the consolidated financial statements. Certain 2002 and 2003 amounts have been reclassified where appropriate to conform with the 2004 presentation. These reclassifications had no effect on the Company's net income (loss) or stockholders' equity.

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.

Estimates of oil and gas reserves, as determined by independent petroleum engineers, are continually subject to revision based on price, production history and other factors. Depletion expense, which is computed based on the units of production method, could be significantly impacted by changes in such estimates. Additionally, FAS 144 requires that if the expected future cash flow from an asset is less than its carrying cost, that asset must be written down to its fair market value. As the fair market value of an oil and gas property will usually be significantly less than the total future net revenue expected from that property, small changes in the estimated future net revenue from an asset could lead to the necessity of recording a significant impairment of that asset.

Property and Equipment

The Company follows the "successful efforts" method of accounting for its oil and gas properties. Under the successful efforts method, costs of acquiring undeveloped oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations. Annual lease rentals and exploration expenses, including geological and geophysical expenses and exploratory dry hole costs, are charged against income as incurred. Costs of drilling and equipping productive wells, including development dry holes and related production facilities, are capitalized. Costs incurred by the Company related to the exploration, development and acquisition of oil and gas properties on behalf of the Partnerships or joint ventures are deferred and charged to the related entity upon the completion of the acquisition.

All other property and equipment are carried at cost. Depreciation and depletion of oil and gas production equipment and properties are determined under the unit-of-production method based on estimated proved recoverable oil and gas reserves. Depreciation of all other equipment is determined under the straight-line method using various rates based on useful lives. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings.

Asset Retirement Obligation:

Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. Our asset retirement obligation primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate our producing properties (including removal of our offshore platforms) at the end of their productive lives, in accordance with applicable state laws. The Company determined its asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Income Taxes:

The Company records income taxes in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109, "Accounting for Income Taxes." SFAS No. 109 is an asset and liability approach to accounting for income taxes, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns.

Deferred tax liabilities or assets are established for temporary differences between financial and tax reporting bases and are subsequently adjusted to reflect changes in the rates expected to be in effect when the temporary differences reverse. A valuation allowance is established for any deferred tax asset for which realization is not likely.

General and Administrative Expenses:

General and administrative expenses represent costs and expenses associated with the operation of the Company. Certain of the Partnerships sponsored by the Company reimburse general and administrative expenses incurred on their behalf.

Income Per Common Share:

Income per share of common stock has been computed based on the weighted average number of common shares outstanding during the respective periods in accordance with SFAS No. 128, "Earnings per Share".

Statements of cash flows:

For purposes of the consolidated statements of cash flows, the Company considers short-term, highly liquid investments with original maturities of less than ninety days to be cash equivalents.

Concentration of Credit Risk:

The Company maintains significant banking relationships with financial institutions in the State of Texas. The Company limits its risk by periodically evaluating the relative credit standing of these financial institutions. The Company's oil and gas production purchasers consist primarily of independent marketers and major gas pipeline companies.

Hedging:

The Company periodically enters into oil and gas financial instruments to manage its exposure to oil and gas price volatility. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The financial instruments are accounted for in accordance with Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities", which established new accounting and reporting requirements for derivative instruments and hedging activities. SFAS No. 133, as amended by SFAS No. 138, requires that all derivative instruments subject to the requirements of the statement be measured at fair market value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in the statement of operations.

Recently Issued Accounting Standards:

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections." Prior to the adoption of the provisions of SFAS No. 145, generally accepted accounting principles required gains or losses on the early extinguishment of debt be classified in a company's periodic consolidated statements of operations as extraordinary gains or losses, net of associated income taxes, below the determination of income or loss from continuing operations. SFAS No. 145 changes generally accepted accounting principles to require, except in the case of events or transactions of a highly unusual and infrequent nature, gains or losses from the early extinguishment of debt be classified as components of a company's income or loss from continuing operations. The adoption of the provisions of SFAS No. 145 in 2003 did not affect the Company's financial position or results of operations.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized and measured initially at fair value only when the liability is incurred. SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. The adoption of SFAS No. 146 in 2003 did not effect on the Company's financial position or results of operations.

In November 2002, the FASB issued Financial Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantee of Indebtedness of Others" (FIN 45). FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of the Interpretation. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. The adoption of FIN 45 did not have an impact on the Company's consolidated financial statements.

In December 2002, the FASB issued SFAS 148, "Accounting for Stock-Based Compensation—Transition and Disclosure." SFAS No. 148 amends FASB Statement No. 123, "Accounting for Stock-Based Compensation" to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure for stock-based employee compensation and the effect of the method used on the reported results. The provisions of SFAS 148 are effective for financial statements with fiscal years ending after December 15, 2002. The adoption of this statement has not impacted the Company's financial position or results of operations.

In January 2003, the FASB issued Financial Interpretation No. 46, "Consolidation of Variable Interest Entities—an interpretation of ARB No. 51" (FIN 46). FIN 46 is an interpretation of Accounting Research Bulletin 51, "Consolidated Financial Statements", and addresses consolidation by business enterprises of variable interest entities (VIE's). 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 VIE's. FIN 46 requires an enterprise to consolidate a variable interest entity if that enterprise has a variable interest that will absorb a majority of the entity's expected losses if they occur, receive a majority of the entity's expected residual return if they occur, or both. An enterprise shall consider the rights and obligations conveyed by its variable interests in making this determination. This guidance applies immediately to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date. It applies in the first fiscal year or interim period beginning after June 15, 2003, to variable interest entities in which an enterprise holds a variable interest that it acquired before February 1, 2003. The adoption of this interpretation did not have an effect on the Company's financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment." SFAS 123R revises SFAS 123, "Accounting for Stock-Based Compensation", and focuses on accounting for share-based payments for services by employer to employee. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation at the grant date. The statement does not require a certain type of valuation model and either a binomial or Black-Scholes model may be used.

The provisions of SFAS 123R are effective for financial statements for fiscal periods ending after June 15, 2005. We are currently evaluating the method of adoption and the impact on our operating results. Our future cash flows will not be impacted by the adoption of this standard.

In February 2005, the FASB released for public comment proposed Staff Position FAS 19-a "Accounting for Suspended Well Costs." This proposed staff position would amend FASB Statement No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" and provides guidance about exploratory well costs to companies who use the successful efforts method of accounting. The proposed position states that exploratory well costs should continue to be capitalized if: 1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and 2) sufficient progress is made in assessing the reserves and the well's economic and operating feasibility. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional disclosures are required to provide information about management's evaluation of capitalized exploratory well costs. In addition, the Staff Position requires the disclosure of: 1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, 2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and 3) an aging of exploratory well costs suspended for greater than one year with the number of wells it related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation.

2. Significant Acquisitions, Dispositions and Property Activity

As more fully described in Note 7, the Company is committed to offer to repurchase the interests of the partners and trust unit holders in certain of the Partnerships. The Company purchased such interests in an amount totaling $ 2,038,305 in 2004, $695,673 in 2003 and $1,203,500 in 2002. The Company's proportionate share of assets, liabilities and results of operations related to the interests in the Partnerships are included in the consolidated financial statements.

Properties under evaluation include $7.5 million invested in one offshore well completed and tested during the third quarter of 2004, however, early production tests have been inconclusive as to the commercial viability of this prospect. Additional expenditures during 2005 will be required to determine whether production rates and ultimate recoverable reserves are sufficient to warrant the costs of setting a platform and installing production facilities.

Effective August 15, 2003 the Company acquired a sixty percent interest in F-W Oil Exploration L.L.C., a licensed Gulf of Mexico operator for a cost of $4,000,000. As of that date FW had approximately 80,000 net acres to develop and a 12.5% working interest in two producing blocks in the Gulf of Mexico. The Company's proportionate share of FW's assets, liabilities and results of operations for the effective period are included in the consolidated financial statements.

3. Accounts Receivable

Accounts receivable at December 31, 2004 and 2003 consisted of the following:

	December 31, 2004	December 31, 2003
Joint interest billing	$ 1,048,000	$ 1,174,000
Trade receivables	1,728,000	1,607,000
Oil and gas sales	6,181,000	3,878,000
Other	324,000	906,000
	9,281,000	7,565,000
Less: allowance for doubtful accounts	(587,000)	(457,000)
Total	$ 8,694,000	$ 7,108,000

4. Other Current Assets

Other current assets at December 31, 2004 and 2003 consisted of the following:

	December 31, 2004	December 31, 2003
Field service inventory	$ 375,000	$ 278,000
Other	58,000	19,000
	$ 433,000	$ 297,000

5. Long-Term Bank Debt

As of December 2002 the Company entered in to a credit agreement with a new primary lender. The Company and the lender agreed to amend and restate in its entirety the credit agreement dated April 26, 1995 between the Company and its predecessor lender. This agreement will continue to provide for borrowings under a Master Note. Advances under the agreement, as amended, are limited to the borrowing base as defined in the agreement. The borrowing base is re-determined by the lender on a semi-annual basis. The borrowing base as of December

31, 2004, was $25 million and included a Term Loan of $4 million. The Term Loan called for monthly installments of $66,667 beginning January 2003. The credit agreement provides for interest on outstanding borrowings at the bank's base rate, as defined, payable monthly, or at rates 2% over the London Inter-Bank Offered Rate (LIBO rate) payable at the end of the applicable interest period.

As of September 2003 the credit agreement was amended to add FW as an additional borrower. As of December 31, 2003 the total outstanding balance owed by FW to the lender was $3,800,000. FW's oil and gas properties are pledged as security under the loan agreement as collateral for amounts due from FW to the lender. The Company's proportionate share of amounts owed by FW to the lender are included in the consolidated financial statements. Total outstanding borrowings under the amended loan agreement as of December 31, 2003 were $28,000,000.

As of December 2004, FW entered into a stand-alone agreement with the same lender and the Company agreement was amended to remove FW as a borrower and eliminate the Company's obligation on amounts owed to the lender by FW. The total outstanding borrowings under the Company's amended loan agreement as of December 31, 2004 were $23,600,000 with $12,679,992 of additional availability. The total outstanding borrowings under the FW loan agreement as of December 31, 2004, were $10,500,000 with $2,500,000 of additional availability. The Company's proportionate share of amounts owed by FW are included in the consolidated financial statements.

Effective March 2005, the lender has agreed to convert the Term Loan into a revolving line of credit with interest rate options to coincide with the existing line of credit. The Company's borrowing base as of March 2005 was determined to be $41,000,000.

The interest rates paid on outstanding borrowings subject to interest at the bank's base rate as of December 31, 2004 and 2003 were 5.25% and 4.5% respectively. During the same periods, the average rates paid on outstanding borrowings bearing interest based upon the LIBO rate were 3.91% and 3.84%. As of December 31, 2004 and 2003, the total outstanding consolidated borrowings were $29,900,000 and $27,280,000, respectively. All borrowings under the Company's credit agreements are due March, 2007.

The Company's oil and gas properties as well as certain receivables and equipment are pledged as security under the loan agreement. The agreement requires the Company to maintain, as defined, a minimum current ratio, tangible net worth, debt coverage ratio and interest coverage ratio, and restrictions are placed on the payment of dividends and the amount of treasury stock the Company may purchase.

6. Commitments

Operating Leases:

The Company has several noncancelable operating leases, primarily for rental of office space, that have a term of more than one year.

Capital Leases:

The Company has two capital leases for office equipment in other long-term obligations. Future minimum lease payments under operating and capital leases are as follows:

	Operating Leases	Capital Leases
2005	349,000	12,000
2006	344,000	—
2007	195,000	—
2008	187,500	—
Thereafter	15,500	—
Total minimum payments	$ 1,091,000	12,000
Less imputed interest		(1,000)
Present value of minimum Lease payments		$ 11,000

Asset Retirement Obligation:

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2004 and 2003 is as follows:

	2004	2003
Asset retirement obligation — beginning of period	$ 300,000	$ —
Liabilities incurred	90,000	300,000
Liabilities settled	(4,900)	(69,000)
Accretion expense	13,500	4,500
Change in estimate	(8,600)	(64,500)
Asset retirement obligation — end of period	$ 390,000	$ 300,000

The Company's liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our wells, the costs to ultimately retire our wells may vary significantly from previous estimates.

7. Contingent Liabilities

The Company, as managing general partner of the affiliated Partnerships, is responsible for all Partnership activities, including the review and analysis of oil and gas properties for acquisition, the drilling of development wells and the production and sale of oil and gas from productive wells. The Company also provides the administration, accounting and tax preparation work for the Partnerships, and is liable for all debts and liabilities of the affiliated Partnerships, to the extent that the assets of a given limited Partnership are not sufficient to satisfy its obligations.

The Company is subject to environmental laws and regulations. Management believes that future expenses, before recoveries from third parties, if any, will not have a material effect on the Company's financial condition. This opinion is based on expenses incurred to date for remediation and compliance with laws and regulations which have not been material to the Company's results of operations.

As a general partner, the Company is committed to offer to purchase the limited partners' interest in certain of its managed Partnerships at various annual intervals. Under the terms of a partnership agreement, the Company is not obligated to purchase an amount greater than 10% of the total partnership interest outstanding. In addition, the Company will be obligated to purchase interests tendered by the limited partners only to the extent of one hundred fifty percent of the revenues received by it from such partnership in the previous year. Purchase prices are based upon annual reserve reports of independent petroleum engineering firms discounted by a risk factor. Based upon historical production rates and prices, management estimates that if all such offers were to be accepted, the maximum annual future purchase commitment would be approximately $500,000.

The Company owns approximately a 27% interest in a limited partnership which owns a shopping center in Alabama. The Company is a guarantor on a mortgage secured by the shopping center. The Company believes the cash flow from the center is sufficient to service the mortgage. The market value of the center is currently substantially higher than the balance owed on the mortgage. If the partnership were unable to pay its obligations under the mortgage agreement, the maximum amount the Company is committed to pay is $200,000.

8. Stock Options and Other Compensation

In May 1989, non-statutory stock options were granted by the Company to four key executive officers for the purchase of shares of common stock. At December 31, 2004 and 2003, options on 767,500 shares were outstanding and exercisable at prices ranging from $1.00 to $1.25.

9. Income Taxes

The components of the provision for income taxes for the years ended December 31, 2004, 2003 and 2002 are as follows:

	2004	2003	2002
Federal:			
Current	$ 187,000	$ 696,000	$ 95,000
Deferred	2,074,000	1,460,000	216,000
State:			
Current	266,000	171,000	104,000
Deferred	496,000	119,000	28,000
Total	$ 3,023,000	$ 2,446,000	$ 443,000

The components of net deferred tax assets (liabilities) are as follows:

	December 31, 2004	December 31, 2003
Current assets		
Compensation and benefits	$ 196,000	$ 196,000
Allowance for doubtful accounts	213,000	178,000
Total current deferred income tax assets	409,000	374,000
Noncurrent assets:		
Alternative minimum tax credits	902,000	393,000
	902,000	393,000
Noncurrent liabilities:		
Basis differences relating to partnerships	468,000	1,351,000
Depletion & depreciation	8,064,000	3,279,000
	8,532,000	4,630,000
Net noncurrent deferred income tax liabilities	$ 7,630,000	$ 4,237,000

The total provision for income taxes for the years ended December 31, 2004, 2003 and 2002 varies from the federal statutory tax rate as a result of the following:

	December 31, 2004	December 31, 2003	December 31, 2002
Expected tax expense	$ 3,501,000	$ 2,770,000	$ 748,000
State income tax, net of federal benefit	503,000	195,000	132,000
Credit for producing fuel from a non-conventional source	—	—	(134,000)
Percentage depletion	(811,000)	(400,000)	(303,000)
Other	(170,000)	(119,000)	—
Tax expense	$ 3,023,000	$ 2,446,000	$ 443,000

For many years prior to 2003, the Company's current taxes were lowered due to the utilization of federal net operating loss and percentage depletion carryforwards. With the filing of the 2002 federal income tax return, all of these carryforwards were used or expired.

In 2002 and prior tax years, the Company was allowed a federal tax credit for producing fuel from a nonconventional source. This credit expired at the end of 2002. To the extent that the credit for producing fuel from a nonconventional source could not be utilized due to the alternative minimum tax, it became part of the Company's alternative minimum tax credit, which may be carried forward indefinitely. Due to the factors discussed above, it is possible that the Company's current tax liabilities in the future will be significantly greater than in past years.

The primary reason that the Company's federal tax expense for both 2004 and 2003 is well below the statutory rate is that the Company is allowed to deduct currently, rather than capitalize, intangible drilling costs as incurred. The current deduction of these costs, which are capitalized for financial accounting purposes, is also the primary reason for the increases in the Company's deferred tax liability in both 2004 and 2003.

The Company is entitled to percentage depletion on certain of its wells, which is calculated without reference to the basis of the property to the extent that such depletion exceeds a property's basis they represent a permanent difference which lowers the Company's effective rate.

10. Segment Information and Major Customers

The Company operates in one industry — oil and gas exploration, development, operation and servicing. The Company's oil and gas activities are entirely in the United States.

The Company sells its oil and gas production to a number of purchasers. Listed below are the percent of the Company's total oil and gas sales made to each of the customers whose purchases represented more than 10% of the Company's oil and gas sales in the year 2004.

Oil Purchasers:		Gas Purchasers:	
Texon Distributing L.P.	26.65%	Unimark LLC	10.29%
Plains All American Inc.	29.29%		
TEPPCO Crude Oil, L.L.C.	16.20%		
LPC Crude Oil, Inc.	16.10%		

Although there are no long-term oil and gas purchasing agreements with these purchasers, the Company believes that they will continue to purchase its oil and gas products and, if not, could be replaced by other purchasers.

11. Related Party Transactions

PEMC acts as the managing general partner, providing administration, accounting and tax preparation services for the Partnerships. Certain directors have limited and general partnership interests in several of these Partnerships. As the managing general partner in each of the Partnerships, PEMC receives approximately 5% to 15% of the net revenues of each Partnership as a carried interest in the Partnerships' properties. As more fully described in Note 7, the Company is committed to offer to repurchase the interests of the partners and trust unit holders in certain of the Partnerships. The Company purchased such interests in an amount totaling $ 2,038,305 in 2004 and $695,673 in 2003.

The Partnership agreements allow PEMC to receive reimbursement for property acquisition and development costs and general and administrative overhead, incurred on behalf of the Partnerships.

Due to related parties at December 31, 2004 and 2003 primarily represents receipts collected by the Company as agent, from oil and gas sales net of expenses. The amount of such receipts due the affiliated Partnerships was $600,000 and $933,000 at December 31, 2004 and 2003, respectively. Receivables from related parties consist of reimbursable general and administrative costs, lease operating expenses and reimbursements for property acquisitions, development, and related costs.

Treasury stock purchases in 2004 and 2003 included shares acquired from related parties. Purchases from related parties include a total of 35,000 shares purchased for a total consideration of $606,100 in 2004, and 37,350 shares purchased for a total consideration of $398,838 in 2003.

12. Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents includes $1,864,000 and $1,479,000 at December 31, 2004 and 2003, respectively, of cash primarily pertaining to unclaimed royalty payments. There were corresponding accounts payable recorded at December 31, 2004 and 2003 for these liabilities.

13. Salary Deferral Plan

The Company maintains a salary deferral plan (the "Plan") in accordance with Internal Revenue Code Section 401(k), as amended. The Plan provides for discretionary and matching contributions which approximated $292,000 and $278,000 in 2004 and 2003, respectively.

14. Earnings per Share

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock. The following reconciles amounts reported in the financial statements:

	Year ended December 31, 2004		
	Net Income	Number of Shares	Per share Amount
Net income per common share	$ 7,275,000	3,569,751	$ 2.04
Effect of dilutive securities:			
Options		722,283	
Diluted net income per common share	$ 7,275,000	4,292,034	$ 1.70

	Year ended December 31, 2003		
	Net Income	Number of Shares	Per share Amount
Net income per common share	$ 5,702,000	3,664,627	$ 1.56
Effect of dilutive securities:			
Options		683,409	
Diluted net income per common share	$ 5,702,000	4,348,036	$ 1.31

	Year ended December 31, 2002		
	Net Income	Number of Shares	Per share Amount
Net income per common share	$ 1,757,000	3,738,753	$ 0.47
Effect of dilutive securities:			
Options		666,839	
Diluted net income per common share	$ 1,757,000	4,405,592	$ 0.40

15. Selected Quarterly Financial Information (Unaudited)

	December 31, 2004	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Revenue	$ 62,428,000	$ 18,530,000	$ 15,540,000	$ 14,987,000	$ 13,371,000
Operating income	10,223,000	3,910,000	2,704,000	1,975,000	1,634,000
Net income	7,275,000	3,133,000	1,756,000	1,232,000	1,154,000
Net income per common share	$ 2.04	$ .89	$ 0.50	$ 0.34	$ 0.32
Diluted net income per common share	$ 1.70	$ .74	$ 0.41	$ 0.29	$ 0.27

	December 31, 2003	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Revenue	$ 46,719,000	$ 12,741,000	$ 12,035,000	$ 10,508,000	$ 11,435,000
Operating income	8,047,000	1,900,000	2,041,000	1,681,000	2,425,000
Net income	5,702,000	1,045,000	1,765,000	1,067,000	1,826,000
Net income per common share	$ 1.56	$ 0.29	$ 0.48	$ 0.29	$ 0.49
Diluted net income per common share	$ 1.31	$ 0.24	$ 0.41	$ 0.25	$ 0.42

PRIMEENERGY CORPORATION and SUBSIDIARIES

SUPPLEMENTARY INFORMATION

(Unaudited)

PRIMEENERGY CORPORATION and SUBSIDIARIES

CAPITALIZED COSTS RELATING to OIL and GAS PRODUCING ACTIVITIES

December 31, 2004, 2003 and 2002

(Unaudited)

	2004	2003	2002
Developed oil and gas properties	$ 95,018,000	$ 91,012,000	$ 74,319,000
Undeveloped oil and gas properties	13,149,000	3,091,000	1,134,000
	108,167,000	94,103,000	75,453,000
Accumulated depreciation, depletion and valuation allowance	60,098,000	53,196,000	46,912,000
Net capitalized costs	$ 48,069,000	$ 40,907,000	$ 28,541,000

COSTS INCURRED in OIL and GAS PROPERTY ACQUISITION,

EXPLORATION and DEVELOPMENT ACTIVITIES

Years ended December 31, 2004, 2003 and 2002

(Unaudited)

	2004	2003	2002
Acquisition of Properties Developed	$ 2,038,000	$ 5,023,000	$ 1,668,000
Undeveloped	10,058,000	873,000	848,000
Exploration Costs	5,499,000	519,000	894,000
Development Costs	7,101,000	12,294,000	8,385,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION and SUBSIDIARIES

STANDARDIZED MEASURE of DISCOUNTED FUTURE
NET CASH FLOWS RELATING to PROVED OIL and GAS RESERVES

Years ended December 31, 2004, 2003 and 2002

(Unaudited)

	2004	2003	2002
Future cash inflows	$ 378,639,000	$ 302,876,000	$ 201,750,000
Future production and development costs	(167,155,000)	(138,929,000)	(104,232,000)
Future income tax expenses	(62,819,000)	(47,696,000)	(24,230,000)
Future net cash flows	148,665,000	116,251,000	73,288,000
10% annual discount for estimated timing of cash flow	(54,254,000)	(42,999,000)	(30,512,000)
Standardized measure of discounted future net cash flows	$ 94,411,000	$ 73,252,000	$ 42,776,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION and SUBSIDIARIES

STANDARDIZED MEASURE of DISCOUNTED FUTURE
NET CASH FLOWS and CHANGES THEREIN
RELATING to PROVED OIL and GAS RESERVES

Years ended December 31, 2004, 2003 and 2002

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2004, 2003 and 2002:

	2004	2003	2002
Sales of oil and gas produced, net of production costs	$ (29,028,000)	$ (17,072,000)	$ (8,120,000)
Net changes in prices and production costs	22,178,000	24,732,000	18,488,000
Extensions, discoveries and improved recovery	18,792,000	14,133,000	8,462,000
Revisions of previous quantity estimates	9,904,000	2,491,000	5,192,000
Reserves purchased, net of development costs	2,238,000	9,667,000	5,824,000
Net change in development costs	(14,000)	8,217,000	(311,000)
Accretion of discount	6,459,000	4,278,000	2,097,000
Net change in income taxes	(9,656,000)	(15,705,000)	(9,809,000)
Other	286,000	(265,000)	(13,000)
Net change	21,159,000	30,476,000	21,810,000
Standardized measure of discounted future net cash flow:			
Beginning of year	73,252,000	42,776,000	20,966,000
End of year	$ 94,411,000	$ 73,252,000	42,776,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION and SUBSIDIARIES

RESERVE QUANTITY INFORMATION

Years ended December 31, 2004, 2003 and 2002

(Unaudited)

	2004		2003		2002	
	Oil (bbls.)	Gas (Mcf)	Oil (bbls.)	Gas (Mcf)	Oil (bbls.)	Gas (Mcf)
Proved developed and undeveloped reserves:						
Beginning of year	2,905,000	39,005,000	2,319,000	29,917,000	1,996,000	24,719,000
Extensions, discoveries and improved recovery	42,000	7,268,000	541,000	4,245,000	273,000	3,011,000
Revisions of previous estimates	268,000	2,806,000	171,000	263,000	198,000	2,798,000
Purchases	88,000	929,000	243,000	8,571,000	173,000	2,929,000
Production	(371,000)	(5,138,000)	(370,000)	(3,991,000)	(321,000)	(3,540,000)
End of year	2,932,000	44,870,000	2,905,000	39,005,000	2,319,000	29,917,000
Proved developed reserves	2,926,000	37,728,000	2,865,000	34,045,000	2,319,000	29,917,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION and SUBSIDIARIES

RESULTS of OPERATIONS from OIL and GAS PRODUCING ACTIVITIES

Years ended December 31, 2004, 2003 and 2002

(Unaudited)

	2004	2003	2002
Revenue:			
Oil and gas sales	$ 43,967,000	$ 29,855,000	$ 18,330,000
Costs and expenses:			
Lease operating expense	14,939,000	12,783,000	10,210,000
Exploration costs	5,499,000	519,000	894,000
Depreciation and depletion	11,021,000	6,283,000	3,988,000
Income tax expense	3,023,000	2,446,000	443,000
	34,482,000	22,031,000	15,535,000
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 9,485,000	$ 7,824,000	$ 2,735,000

See accompanying notes to supplementary information.

(Unaudited)

1. **Presentation of Reserve Disclosure Information**

Reserve disclosure information is presented in accordance with the provisions of Statement of Financial Accounting Standards No. 69 ("SFAS 69"), "Disclosures About Oil and Gas Producing Activities".

2. **Determination of Proved Reserves**

The estimates of the Company's proved reserves were determined by an independent petroleum engineer in accordance with the provisions of SFAS 69. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development and other factors. Estimated future net revenues were computed by reserves, less estimated future development and production costs based on current costs.

3. **Results of Operations from Oil and Gas Producing Activities**

The results of operations from oil and gas producing activities were prepared in accordance with the provisions of SFAS 69. General and administrative expenses, interest costs and other unrelated costs are not deducted in computing results of operations from oil and gas activities.

4. **Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves**

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes of standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with the provisions of SFAS 69.

Future cash inflows are computed as described in Note 2 by applying current prices to year-end quantities of proved reserves.

Future production and development costs are computed estimating the expenditures to be incurred in developing and producing the oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying the year-end U.S. tax rate to future pre-tax cash inflows relating to proved oil and gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences and tax credits and allowances relating to the proved oil and gas reserves.

Future net cash flows are discounted at a rate of 10% annually (pursuant to SFAS 69) to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily represent an estimate of fair market value or the present value of such cash flows since future prices and costs can vary substantially from year-end and the use of a 10% discount figure is arbitrary.

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Corporate Information

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James F. Gilbert
Dallas, Texas

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Annual Meeting

June 3, 2005 at 8:30 a.m.
Roger Sherman Inn
New Caanan, Connecticut

NASDAQ Symbol

PNRG

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(203) 358-5700

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Midland, Texas
Oklahoma City, Oklahoma
Charleston, West Virginia

Field Offices:

Kingfisher, Oklahoma
Garvin, Oklahoma
Carrizo Springs, Texas
Midland, Texas
Orma, West Virginia

PrimeEnergy Management Corporation

Stamford, Connecticut

Eastern Oil Well Service Company

Houston, Texas
Midland, Texas
Oklahoma City, Oklahoma
Charleston, West Virginia

Southwest Oilfield Construction Company

Kingfisher, Oklahoma

10-K Information

The Company's 2004 Annual Report on Form 10-K, as filed with the Securities and Exchange Commission (except for exhibits) is included herein. Exhibits to the Form 10-K, which are indexed therein, are available upon request and the payment of a reproduction charge of fifteen cents per page by writing to:

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President and Chief Executive Officer

James F. Gilbert
Secretary

Beverly A. Cummings
Executive Vice President, Treasurer and
Chief Financial Officer

Directors

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PrimeEnergy Corporation

Charles E. Drimal, Jr.
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PrimeEnergy Corporation
2004 Annual Report