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PrimeEnergy

PrimeEnergy Corporation

ANNUAL REPORT
2006

President's Letter

PrimeEnergy had an outstanding year in 2006 and we are pleased to report several significant accomplishments. First, the Company as of December 31, 2006, had proved reserves of 69.233 bcf of natural gas and 4.228 million barrels of oil; both of these reserve categories are the largest recorded in the Company's history. Second, the Company established a record for yearly production rates for both oil and natural gas as it produced 379,000 barrels of oil and 5.695 million mcf of natural gas. Third, the Company's revenues grew from $75,946,000 to $92,419,000 and assets grew from $109,383,000 to $291,592,000. However, I would be remiss if I did not point out our debt also grew from $28,050,000 to $136,460,000.

We are also pleased to have been recognized in Fortune Magazine as the forty-fifth fastest growing public company in America. For a second year in a row we were also listed in Fortune Small Business Magazine as one of the fastest growing small public companies in America. Our position in the ranking changed from sixtieth in 2005 to eleventh in 2006. I believe everyone associated with the Company should be very proud of these accolades.

We are also proud of the growth 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 2006 our oil field service equipment and facilities had a fair-market value of approximately $20,000,000.

While experiencing reserve growth, the expansion of our well service businesses, and the development of both our onshore and offshore operations, we have also been able to continue to reduce the outstanding shares of our Company. Since 1990, we have retired 4,500,649 shares of stock at an average price of $6.49. This represents approximately 58.5% of the outstanding common stock. The Company also retired 769,500 options at a cost of $607,000. In 2007, we plan to allocate part of our cashflow to our stock repurchase program.

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. We expect to continue to make significant capital expenditures over the next several years as part of this plan. We have budgeted $60 million for capital expenditures in 2007. We project that we will spend $40 million in the Gulf of Mexico and $20 million on onshore wells. Last year the total capital expenditures were approximately $160 million dollars.

It was with great regret we announced the resignation of Gaines Wehrle from the PrimeEnergy Corporation Board of Directors in February of 2007. His resignation was a requirement of a recent purchase of controlling interest in the McJunkin Corporation by affiliates of The Goldman Sachs Group, Inc. We remain deeply grateful for his contributions and advice to PrimeEnergy over the last twenty years.

PrimeEnergy remains committed to developing domestic reserves and building on our knowledge and operating presence in the Gulf of Mexico, Southwest and the Appalachian Basin. 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

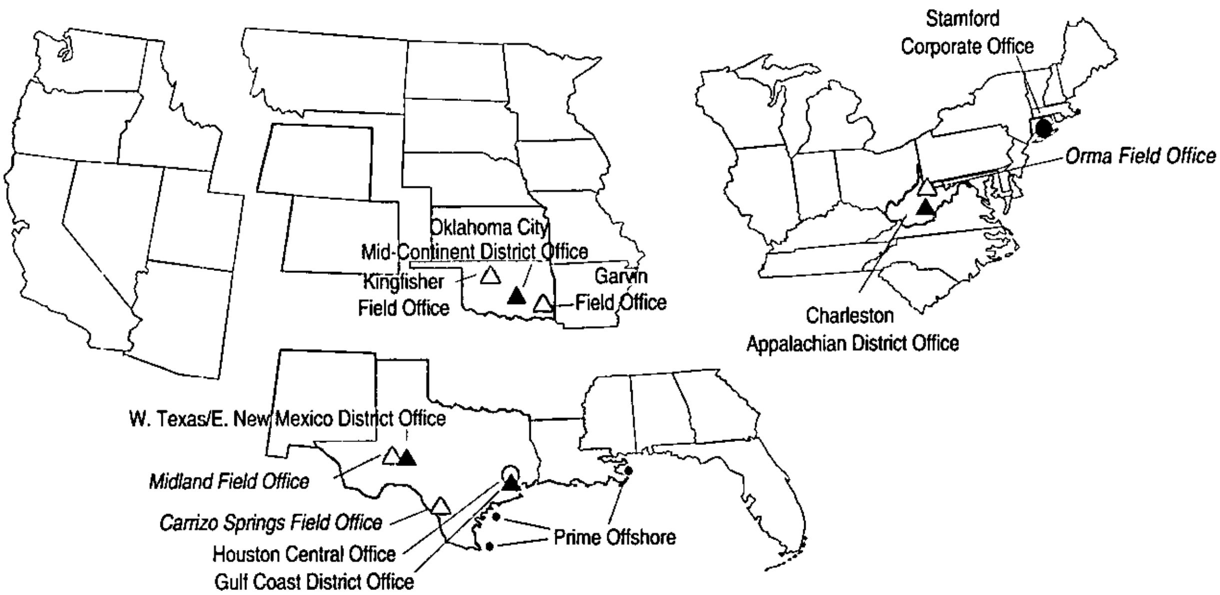
The Company

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 1,545 wells and owns non-operating interests in approximately 800 additional wells. The Company's off-shore operations in the Gulf of Mexico are conducted through its subsidiary, Prime Offshore L.L.C., with its offices in Houston, Texas.

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, 2006, as filed with the Securities and Exchange Commission is reproduced herein (except for exhibits) as the Company's Annual Report for 2006 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.

		2006	2005	2004	2003	2002
Revenues	$	92,419,000	75,946,000	62,428,000	46,719,000	34,186,000
Income from operations	$	27,584,000	22,151,000	10,223,000	8,047,000	2,168,000
Net Income	$	18,300,000	25,955,000	7,275,000	5,702,000	1,757,000
Income per common share	$	5.52	7.64	2.04	1.56	0.47
Diluted net income per common share	$	4.50	6.27	1.70	1.31	0.40
Net cash provided by operations	$	31,982,000	18,605,000	26,995,000	19,622,000	9,644,000
Total assets	$	291,592,000	109,383,000	69,926,000	58,255,000	44,909,000
Long-term obligations	$	168,141,000	44,126,000	30,290,000	26,925,000	23,734,000
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, 2006

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, CT (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 by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes [ ] No [X]

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 of Section 15 (d) of the Act.

Yes [ ] No [X]

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-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

[X]

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. Large Accelerated Filer[ ] Accelerated Filer [ ] Non-Accelerated Filer [X]

Indicated by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

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 $56,753,549.

The number of shares outstanding of each class of the Registrant's Common Stock as of March 26, 2007, was: 3,194,731 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, 2007, are incorporated by reference in Part III hereof.

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PrimeEnergy Corporation

FORM 10-K ANNUAL REPORT
For the Fiscal Year Ended
December 31, 2006

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, Colorado and Louisiana. The Company, through its 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 subsidiary Prime Offshore L.L.C, formerly F-W Oil Exploration L.L.C. The Company is also active in the acquisition of producing oil and gas properties through joint ventures with industry partners. The Company's subsidiary, PrimeEnergy Management Corporation ("PEMC"), acts as the managing general partner of 18 oil and gas limited partnerships (the "Partnerships"), 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 31, 2006, the Company had net capitalized costs related to oil and gas properties of $289 million, including $5 million of undeveloped properties. Total expenditures for the acquisition, exploration and development of the Company's properties during 2006 were $160 million of which $1.2 million related to exploration costs expensed during 2006. Proved reserves as of December 31, 2006, were 94 BCFe of gas which consisted of 96% proved developed reserves and 4% proved undeveloped reserves.

Our offshore exploration and development budget for 2007 is $40 million including facility construction and installation. As of March, 2007, the Company has spent approximately $22 million drilling, completing and equipping wells in the Gulf of Mexico as part of our program to develop our offshore properties. We have budgeted $20 million for onshore exploration and development in our core operating areas. As of March, 2007, the Company has committed approximately $7.2 million on wells in these areas that have been spudded since January 1, 2007.

Significant 2006 activity

During 2006, we participated in drilling a total of 75 gross wells, 74 successful wells and 1 dry hole. Offshore wells totaled 12, West Texas wells totaled 41 and the remaining wells were drilled either in our core operating areas or under joint operating agreements where we are not the operator. All of the successful onshore wells and 4 of the offshore wells are currently producing. The remaining offshore wells have successfully tested gas production and the Company is currently completing construction of pipelines and production facilities and expects to commence production during the second quarter of 2007.

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, Colorado 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 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 1,545 oil and gas wells, 414 through the Houston office, 188 through the Midland office, 446 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 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, 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 3,775. 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 and plugging and abandonment, drilling bonds 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.

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.	36%
Plains All American Inc.	38%
TEPPCO Crude Oil, L.L.C.	11%
Gas Purchasers:	
Unimark LLC	25%
Cokinos Energy Corporation	23%

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, and 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. The 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 2007, the Company had 229 full-time and 14 part-time employees, 21 of whom were employed by the Company at its principal offices in Stamford, Connecticut, 28 in Houston, Texas, at the offices of Prime Operating Company, Eastern Oil Well

Service Company, EOWS Midland Company and Prime Offshore L.L.C., and 194 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 1A. RISK FACTORS.

Natural gas and oil prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results. Because our reserves are predominantly natural gas, changes in natural gas prices may have a particularly large impact on our financial results.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of consumer product demand;
- weather conditions;
- political conditions in natural gas and oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;
- actions of governmental authorities;
- pipeline capacity constraints;
- inventory storage levels;
- domestic and foreign governmental regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. If natural gas prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including:

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

- compliance with governmental requirements; and

- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate for activity within a particular geographic area may decline. We may ultimately not be able to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may not be able to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;

- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;

- the approval of the prospects by other participants after additional data has been compiled;

- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;

- our financial resources and results; and

- the availability of leases and permits on reasonable terms for the prospects.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysic, engineering and production data. As a result, estimates of different engineers may vary. In addition, the extent, quality and reliability of this technical data can vary. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;

- the interpretation of that data

- the accuracy of various mandated economic assumptions; and

- the judgment of the persons preparing the estimate.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and crude oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves. You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board in Statement of Financial Accounting Standards No. 69 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop economically. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

Exploration, development and exploitation activities involve numerous risks that may result in dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating opportunities to acquire natural gas and oil properties. We may not be able to successfully consummate any acquisition, to acquire producing natural gas and oil properties that contain economically recoverable reserves, or to integrate the properties into our operations profitably.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;
- mechanical problems;
- uncontrolled flows of natural gas, oil or well fluids;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

In addition, we conduct operations in shallow offshore areas, which are subject to additional hazards of marine operations, such as capsizing, collision and damage from severe weather. Any of these events could result in injury or loss of human life, loss of hydrocarbons, significant damage to or destruction of property, environmental pollution, regulatory investigations and penalties, impairment of our operations and substantial losses to us.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Our ability to sell our natural gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. Our failure to obtain these services on acceptable terms could materially harm our business.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. These hedging arrangements limit the benefit to us of increases in prices. We will continue to evaluate the benefit of employing derivatives in the future.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is extremely intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including tax laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

Item 1B. UNRESOLVED STAFF COMMENTS.

The Company is a non-accelerated filer and no response is required pursuant to this Item.

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 Prime Offshore 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, 2006.

	2006		2005		2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory:										
Oil	—	—	1	.500	2	.400	—	—	1	1.000
Gas	5	3.750	11	3.510	10	2.850	4	1.565	1	.250
Dry	1	.400	1	1.000	4	1.594	6	1.400	4	2.500
Development:										
Oil	41	22.141	17	8.500	—	—	6	2.561	2	1.250
Gas	28	11.664	15	7.790	7	3.993	8	4.478	10	7.590
Dry	—	—	4	2.410	2	1.594	1	.500	6	5.300
Total:										
Oil	41	22.141	18	9.000	2	.400	6	2.560	3	2.250
Gas	33	15.414	26	11.300	17	6.843	12	6.042	11	7.840
Dry	1	.400	5	3.410	6	2.722	7	1.900	10	7.800
	75	37.955	49	23.710	25	9.965	25	10.504	24	17.890

Oil and Gas Production

As of December 31, 2006, 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	842	264.70
Gas Wells	1,177	386.51
Producing Acres	294,568.05	90,810.59

(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, 2006. "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.

	2006	2005	2004	2003	2002
Oil (barrels)	379,000	361,000	371,000	370,000	321,000
Gas (Mcf)	5,695,000	4,758,000	5,138,000	3,991,000	3,540,000

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, 2006.

	2006	2005	2004	2003	2002
Average sales price per barrel	$ 61.47	$ 52.91	40.45	28.90	23.37
Average sales price Per Mcf	$ 6.78	$ 7.33	5.64	4.80	3.06
Average production costs per net equivalent barrel (1)	$ 15.84	$ 16.10	12.17	12.42	11.80

(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, 2006. "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	130,316	74,573				
Montana			13,984	59	786	5
Nebraska			2,553	331		
North Dakota			640	1		
Oklahoma	6,118	3,765	320	1		
Texas	13,470	6,828	680	16		
New Mexico	188	62				
Wyoming	1,000	125	5,043	35	140	35
TOTAL	151,092	85,353	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, 2006. 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)
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
2005	3,504,000	43,976,000	183,000	968,000	3,687,000	44,944,000
2006	4,009,000	66,754,000	219,000	2,479,000	4,228,000	69,233,000

The estimated future net revenue (using current prices and costs as of those dates:) 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, 2006, 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 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	Standardized Measure of Discounted Cash flow
2002	$ 97,600,000	56,855,000	–	–	97,600,000	56,855,000	14,079,000	42,776,000
2003	$ 141,194,000	85,695,000	22,891,000	17,401,000	164,085,000	103,096,000	29,844,000	73,252,000
2004	$ 177,916,000	107,116,000	33,484,000	26,796,000	211,400,000	133,912,000	39,501,000	94,411,000
2005	$ 349,816,000	201,883,000	12,510,000	6,663,000	362,326,000	208,546,000	63,067,000	145,479,000
2006	$ 360,665,000	242,216,000	13,836,000	7,077,000	374,501,000	249,293,000	50,670,000	198,623,000

The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of the PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flow attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%.

"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, 2006 and 2005, was $5.62 and $10.05 per MMBTU, respectively. The range of spot prices during the year 2006 was a low of $3.66 and a high of $9.95 and the average was $6.76. The range during the first quarter of 2007 has been from $5.50 to $8.98, with an average of $7.27. The recent futures market prices have traded above $6.72 per MMBTU.

The NYMEX price for oil at December 31, 2006 and 2005, was $61.06 and $61.04 per barrel, respectively. The range of NYMEX prices during the year 2006 was a low of $56.26 and a high of $77.03 and the average was $66.14. The range during the first quarter of 2007 has been from $50.48 to $62.91, with an average of $57.93. The recent futures market prices have fluctuated around $62.00.

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, 2007, 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, 2006, to a vote of the Company's security-holders through the solicitation of proxies or otherwise.

PART II

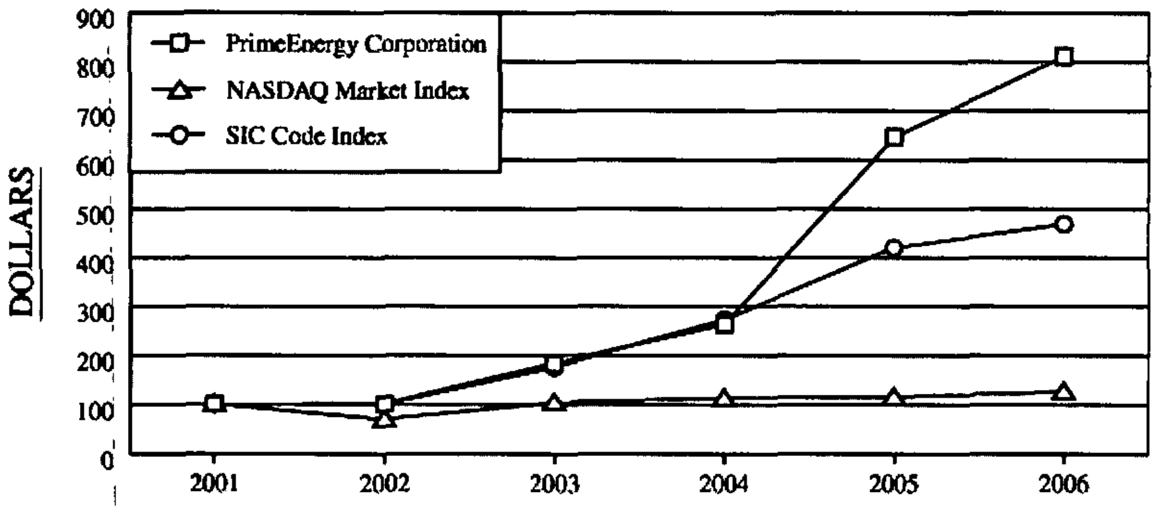
Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that PrimeEnergy Corporation specifically incorporates it by reference into such filing.

The following graph illustrates the yearly percentage change in the cumulative stockholder return on our common stock, compared with the cumulative total return on The Nasdaq Stock Market (U.S. Companies) Index and the Nasdaq Stocks — Crude Petroleum and Natural Gas Index, for the five years ended December 31, 2006.

Comparison of Five Year Cumulative Total Return
PrimeEnergy Corporation Stock Price vs. NASDAQ AND NASDAQ E&P INDICES

Value of Investment of $100 on December 31, 2001



As of December 31	2001	2002	2003	2004	2005	2006
PrimeEnergy Corporation	$ 100.0	$ 100.5	$ 183.5	$ 262.2	$ 645.7	$ 810.3
NASDAQ Market Index	100.0	69.1	103.4	112.5	114.9	126.2
Peer Group Index	100.0	99.3	175.4	272.2	420.0	468.5

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, 2006, were as follows:

2006	High	Low	2005	High	Low
First Quarter	$ 83.42	$ 48.83	First Quarter	$22.99	$19.50
Second Quarter	$ 86.75	$ 66.35	Second Quarter	$47.09	$19.77
Third Quarter	$ 81.26	$ 59.09	Third Quarter	$52.49	$28.12
Fourth Quarter	$ 72.98	$ 64.05	Fourth Quarter	$52.52	$36.00

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 15, 2007, was 858.

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.

Issuer Purchases of Equity Securities

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. On November 10, 2006, the board of Directors authorized the Company to purchase up to an additional 300,000 shares of its Common Stock. Through December 31, 2006, we repurchased a total of 2,334,106 shares under this program for $24,699,359 at an average price of $10.58 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.

2006 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Program
January	21,890	49.74	154,994
February	1,503	56.80	153,491
March	1,243	61.97	152,248
April	—	—	152,248
May	9,362	75.79	142,886
June	10,000	70.00	132,886
July	10,041	63.98	122,845
August	21,298	69.00	101,547
September	5,924	77.74	95,623
October	18,832	70.02	376,791
November	7,313	69.18	369,478
December	3,584	67.65	365,894
Total/Average/Remainder	110,990	65.89	

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.

	2006	2005	2004	2003	2002
Revenues	$ 92,419,000	75,946,000	62,428,000	46,719,000	34,186,000
Income from operations	$ 27,584,000	22,151,000	11,359,000	8,047,000	2,168,000
Net income	$ 18,300,000	25,955,000	7,275,000	5,702,000	1,757,000
Income per common share	$ 5.52	7.64	2.04	1.56	0.47
Diluted net income per common share	$ 4.50	6.27	1.70	1.31	0.40
Total assets	$ 291,572,000	109,383,000	69,926,000	58,255,000	44,887,000
Long-term obligations	$ 168,141,000	44,126,000	30,290,000	26,925,000	23,734,000
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, 2006, was $31.9 million, compared to $18.6 million in the prior year. The change reflects the 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 2007 because of higher projected production from new properties, combined with oil and gas prices consistent with 2006 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.

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 $60 million for capital expenditures in 2007. We project that we will spend $40 million in the Gulf of Mexico and $20 million on onshore wells.

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 successful wells 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 2006 was $7.8 million. The Company expects to expend a similar amount in 2007.

The Company currently maintains two credit facilities totaling $360 million, with a combined current borrowing base of $156.5 million. The bank reviews 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.

Critical Accounting Estimates:

Proved Oil and Gas Reserves

Proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate, and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit-of-production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Repurchase of limited partners' interests

The quantities of estimated proved oil and gas reserves are a significant component of the calculation of amounts offered for partnership interests acquired pursuant to our repurchase commitment. Revisions in such estimates may alter the amount of our future annual commitments. Holding all other factors constant, if reserves were revised upward or downward, repurchase offer amounts would increase or decrease respectively.

Results of Operations:

2006 as compared to 2005

The Company had net income of $18,300,000 in 2006 as compared to $25,955,000 in 2005.

Oil and gas sales were $61,924,000 in 2006 as compared to $53,988,000 in 2005. A chart summarizing oil and gas production and revenue is presented below.

	2006	2005	Increase (Decrease)
Barrels of Oil Produced	379,000	361,000	18,000
Average Price Received (rounded)	$ 61.47	$ 52.91	$ 8.56
Oil Revenue	$ 23,300,000	$ 19,100,000	$ 4,200,000
Mcf of Gas Produced	5,695,000	4,758,000	937,000
Average Price Received (rounded)	$ 6.78	$ 7.33	$ (0.55)
Gas Revenue	$ 38,625,000	$ 34,888,000	$ 3,737,000
Total Oil & Gas Revenue	$ 61,924,000	$ 53,988,000	$ 7,936,000

Changes in Production are due to additional production from properties added during late 2005 and throughout 2006.

Field Service Income increased to $20,319,000 in 2006 from $15,182,000 in 2005. This increase reflects higher utilization of equipment during 2006 combined with rate increases.

Lease operating expenses increased by 12% to $21,040,000 in 2006 as compared to $18,753,000 in 2005. The difference is attributable to costs on properties added during late 2005 and throughout 2006 and repairs made to marginal wells currently economic due to higher product price levels. This increase also reflects the overall price increase in oil field services.

General and administrative expenses increased to $12,400,000 in 2006 as compared to $10,493,000 in 2005, reflecting the increased ownership of the Partnerships combined with reduced reimbursements from the Partnerships and increases in personnel costs and professional fees. The $1,907,000 increase includes $1,313,000 representing the fair market value of subsidiary stock issued to two key executives.

Depreciation and depletion of oil and gas properties increased to $14,437,000 in 2006 from $10,125,000 in 2005. This increase reflects the increased production and cost basis of the Company's properties.

Exploration costs of $1,162,000 were incurred during 2006. These costs include $588,000 related to the drilling of unsuccessful exploratory wells and $573,655 of certain geological, geophysical and seismic costs.

Interest expense increased to $2,091,000 in 2006 from $1,531,000 in 2005 due to increased average outstanding debt combined with increased interest rates. The average interest rates paid on outstanding borrowings subject to interest during 2006 and 2005 were 8.80% and 5.35% respectively. As of December 31, 2006 and 2005, the total outstanding borrowings were $136,460,000 and $28,050,000, respectively.

Income tax expense of $10,210,000 in 2006 represents a 36% effective rate as compared to the effective rate of 37% in 2005. At higher rates of income, the Company's percentage depletion deductions, which are currently its only major permanent difference, become less significant as a percentage of income. Current tax benefit in 2006 was $1,348,000 with the remainder being attributable to an increase in the Company's deferred tax liability.

The primary reason that the Company's current federal tax expense for 2006 is 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 2006 and 2005.

2005 as compared to 2004

The Company had net income of $25,955,000 as compared to $7,275,000 in 2004.

Oil and gas sales were $53,988,000 in 2005 as compared to $43,964,000 in 2004. A chart summarizing oil and gas production and revenue is presented below.

	2005	2004	Increase (Decrease)
Barrels of Oil Produced	361,000	371,000	(10,000)
Average Price Received (rounded)	$ 52.91	$ 40.45	$ 12.46
Oil Revenue	$ 19,100,000	$ 15,006,000	$ 4,094,000
Mcf of Gas Produced	4,758,000	5,138,000	(380,000)
Average Price Received (rounded)	$ 7.33	$ 5.64	$ 1.69
Gas Revenue	$ 34,888,000	$ 28,961,000	$ 5,297,000
Total Oil & Gas Revenue	$ 53,988,000	$ 43,967,000	$ 10,021,000

Changes in Production are due to additional production from properties added during 2004 and 2005 offset by the sale of offshore properties in August 2005 (Partners transaction) and the hurricanes in the third quarter of 2005. Hurricanes Katrina and Rita came ashore negatively affecting our offshore production and to a lesser extent a portion of our onshore production. While we did not incur any significant property damage as a result of either storm production during the third quarter was shut-in for periods ranging from several days to a few weeks, primarily because of a lack of power or because of flooding or damage to facilities receiving our production.

Field Service Revenue increased to $15,182,000 in 2005 from $11,965,000 in 2004. This increase reflects higher utilization of equipment during 2005 combined with rate increases.

Lease operating expenses increased by 24% to $18,573,000 in 2005 as compared to $14,939,000 in 2004. The difference is attributable to production taxes related to higher prices combined with costs on properties added during 2005 and repairs made to marginal wells currently economic due to higher product price levels. This increase also reflects the overall price increase in oil field services.

General and administrative expenses increased to $10,493,000 in 2005 as compared to $7,536,000 in 2004, reflecting the increased ownership of the Partnerships combined with reduced reimbursements from the Partnerships and increases in personnel costs and professional fees.

Depreciation and depletion of oil and gas properties decreased by 8% to $ 10,125,000 in 2005 from $11,021,000 in 2004. This decrease reflects the declining cost basis of the Company's onshore properties combined with the sale of the offshore properties in August 2005 (Partners transaction).

Exploration costs of $664,000 were incurred during 2005. These costs include $262,000 related to the drilling of a dry hole in Oklahoma. Exploration costs in 2004 of $5,499,000 consist of dry hole expenditures and certain geological, geophysical and seismic costs.

Interest expense increased to $1,531,000 in 2005 from $1,136,000 in 2004 due to increased average outstanding debt combined with increased interest rates. The average interest rates paid on outstanding borrowings subject to interest during 2005 and 2004 were 5.35% and 3.91% respectively. As of December 31, 2005 and 2004, the total outstanding borrowings were $28,050,000 and $29,900,000, respectively.

Income tax expense of $14,999,000 in 2005 represents a 37% effective rate as compared to the effective rate of 29% in 2004. At higher rates of income, the Company's percentage depletion deductions, which are currently its only major permanent difference, become less significant as a percentage of income. Current tax expense in 2005 was $8,814,000 with the remainder being attributable to an increase in the Company's deferred tax liability.

The primary reason that the Company's current federal tax expense for 2005 is 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 2005 and 2004.

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, 2006, a hypothetical 2.5% increase in the applicable interest rates would increase interest expense by approximately $1,285,000.

Derivative Instruments and Hedging Activity.

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to us of increases in prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please read the discussion below and note 11 of the Notes to Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

Hedges on Production – Collars.

From time to time, we enter into natural gas and crude oil collar agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under the collar arrangements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. In the case of a three-way collar if the index price rises above the third tier price, the counterparty pays us.

Hedges on Production – Swaps.

From time to time, we enter into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under the swap agreements, if the index price rises above the swap price, we pay the counterparty. If the index falls below the swap price, the counterparty pays us.

At December 31, we had open crude oil price collar contracts covering our 2007 and 2008 production as follows:

Contract Period	Volume In Mbbl	Crude Oil Price Collar Weighted Average Price Floor/Ceiling/Third Tier (per Bbl)	Net Unrealized (Loss)/Gain (In thousands)
First Quarter 2007	39	$65/ $79.25/ $100.00	
Second Quarter 2007	33	$65/ $79.25/ $100.00	
Third Quarter 2007	28	$65/ $79.25/ $100.00	
Fourth Quarter 2007	22	$65/ $79.25/ $100.00	
Full Year 2007	122		$ 173,000
First Quarter 2008	23	$65/ $79.25/ $100.00	
Second Quarter 2008	21	$65/ $79.25/ $100.00	
Third Quarter 2008	20	$65/ $79.25/ $100.00	
Fourth Quarter 2008	18	$65/ $79.25/ $100.00	
Full Year 2008	82		$ —

At December 31, 2006, we had open natural gas price swap contracts covering our 2007 and 2008 production as follows:

	Natural Gas Price Swaps		
Contract Period	Volume in Mmcf	Weighted Average Price (per Mcf)	Net Unrealized Gain (In thousands)
First Quarter 2007	905	$ 10.25	$ 3,393
Second Quarter 2007	880	8.32	1,287
Third Quarter 2007	720	8.51	955
Fourth Quarter 2007	275	9.53	276
Full Year 2007	2,780	$ 9.12	$ 5,911
First Quarter 2008	75	$ 9.02	$ 43
Second Quarter 2008	75	9.02	101
Third Quarter 2008	75	9.02	85
Fourth Quarter 2008	75	9.02	27
Full Year 2008	300	$ 9.02	$ 256

We are exposed to market risk on these open contracts, to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in future market prices of energy commodities. See "Forward-Looking Information" for further details.

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. 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 which may result in changes to our internal control over financial reporting.

Item 9B. OTHER INFORMATION.

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company's Directors, nominees for Directors and executive officers is included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June, 2007, which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2006, 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, 2007, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2006, 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 to the Company's Annual Meeting of Stockholders to be held in June, 2007, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2006, and which is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Information relating to certain transactions by Directors and executive officers of the Company is included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June, 2007, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2006, 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, 2007, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2006, 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 at page F-1 of this Report)

3. Exhibits:

3.1	Restated Certificate of Incorporation of PrimeEnergy Corporation (Incorporated by reference to Exhibit 3.1 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2004)
3.2	Bylaws of PrimeEnergy Corporation (Incorporated by reference to Exhibit 3.2 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2004)
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 Contribution Prototype 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 10.3.1 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2002) (1)
10.3.2	First Amendment to the PrimeEnergy Corporation Employees 401(k) Savings Plan (filed herewith)
10.4	Amended and Restated Agreement of Limited Partnership, FWOE Partners L.P., dated as of August 22, 2005 (Incorporated by reference to Exhibit 10.3 of PrimeEnergy Corporation Form 8-K for events of August 22, 2005)
10.4.1	Contribution Agreement between F-W Oil Exploration L.L.C. and FWOE Partners L.P. dated as of August 22, 2005 (Incorporated by reference to exhibit 10.4 of PrimeEnergy Corporation Form 8-K for events of August 22, 2005)
10.18	Composite copy of Non-Statutory Option Agreements (Incorporated by reference to Exhibit 10.18 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2004) (1)
10.22.5	Amended and Restated Credit Agreement among PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank, FSB as Agent and Letter of Credit Issuer and BNP Paribas, as Co-Documentation Agent and JPMorgan Chase Bank, N.A., as Co-Documentation Agent and the Lenders Signatory hereto, December 28, 2006 (filed herewith)
10.22.5.1	Letter from BNP Paribas regarding Amended and Restated Credit Agreement effective as of December 28, 2006, among PrimeEnergy Corporation, et al, and Guaranty Bank, FSB (filed herewith)
10.23.2	Amended and Restated Security Agreement between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company, (debtor) and Guaranty Bank, FSB as Agent (secured party) December 28, 2006 (filed herewith)
10.23.3	Amended and Restated Security Agreement (Membership Pledge) by PrimeEnergy Corporation in favor of Guaranty Bank, FSB as Agent December 28, 2006 (filed herewith)
10.23.4	Amended and Restated Security Agreement between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company, (debtor) and Guaranty Bank, FSB as Agent (secured party) December 28, 2006 (filed herewith)

10.23.5	Amended and Restated Security Agreement between Eastern Oil Well Service Company, EOWS Midland Company,(debtor) and Guaranty Bank, FSB as Agent (secured party) December 28, 2006 (filed herewith)
10.23.6	Security Agreement between Eastern Oil Well Service Company, EOWS Midland Company,(debtor) and Guaranty Bank, FSB as Agent (secured party) December 28, 2006 (filed herewith)
10.23.7	Amended and Restated Security Agreement between Southwest Oilfield Construction Company, (debtor) and Guaranty Bank, FSB as Agent (secured party) December 28, 2006 (filed herewith)
10.23.8	Amended and Restated Security Agreement effective between EOWS Midland Company, (debtor) and Guaranty Bank, FSB as Agent (secured party) December 28, 2006 (filed herewith)
10.25	Credit Agreement dated as of June 1, 2006 (but effective for all purposes as of August 22, 2005), between Prime Offshore L.L.C. as Borrower and PrimeEnergy Corporation as Lender (filed herewith)
10.26	Credit Agreement dated June 29, 2006 between Prime Offshore L.L.C. and Guaranty Bank, FSB as Agent and a Lender (filed herewith)
10.26.1	Subordination Agreement effective as of June 29, 2006, between Prime Offshore L.L.C., PrimeEnergy Corporation, and Guaranty Bank, FSB (filed herewith)
10.27	Security Agreement effective June 29, 2006 between Prime Offshore L.L.C., and Guaranty Bank, FSB (debtor) and Guaranty Bank, FSB as Agent (secured party) (filed herewith)
10.27.1	Mortgage, Deed of Trust, Security Agreement, Financing Statement and Assignment of Production effective as of June 29, 2006, from Prime Offshore L.L.C. and Guaranty Bank, FSB (filed herewith)
10.27.2	Pledge Agreement as of June 29, 2006, between Guaranty Bank, FSB and Prime Offshore L.L.C. (filed herewith)
10.28	Completion and Liquidity Maintenance Agreement effective as of June 29, 2006, between PrimeEnergy Corporation, Guaranty Bank, FSB, and Prime Offshore, L.L.C. (filed herewith)
10.29	Put Right Agreement effective as of June 29, 2006, by and among PrimeEnergy Corporation and Prime Offshore L.L.C. (filed herewith)
14	PrimeEnergy Corporation Code of Business Conduct and Ethics (filed herewith)
21	Subsidiaries (filed herewith)
23	Consent of Ryder Scott & Company L.P. (filed herewith)
31.1	Certification of Chief Executive Officer pursuant to Rule 13(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 Rule 13(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. Section 1350, adopted pursuant to Section 906 of the Sarbanes-OxleyAct of 2002 (filed herewith)
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-OxleyAct of 2002 (filed herewith)

(1) Management contract or compensatory plan or arrangement required to be filed as an Exhibit to this Form 10-K

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 30th day of March, 2007.

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 30th day of March, 2007.

/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		

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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, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31, 2006, 2005 and 2004. 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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, 2006 and 2005, and the consolidated results of its operations and cash flows for the years ended December 31, 2006, 2005 and 2004 in conformity with accounting principles generally accepted in the United States of America.

PUSTORINO, PUGLISI & CO., LLP
New York, New York
March 30, 2007

PRIMEENERGY CORPORATION and SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS, December 31, 2006 and 2005

	2006	2005
ASSETS:		
Current assets:		
Cash and cash equivalents	$ 24,653,000	$ 11,119,000
Restricted cash and cash equivalents	2,528,000	1,797,000
Accounts receivable, net	32,970,000	16,558,000
Due from related parties	655,000	985,000
Prepaid expenses	1,269,000	7,517,000
Derivative contracts	6,085,000	—
Inventory at cost	3,521,000	388,000
Deferred income taxes	—	454,000
Total current assets	71,681,000	38,818,000
Property and equipment, at cost:		
Proved oil and gas properties at cost	284,698,000	125,248,000
Unproved oil and gas properties at cost	5,047,000	6,166,000
Less, accumulated depletion and depreciation	(78,005,000)	(65,234,000)
	211,740,000	66,180,000
Field and office equipment	15,793,000	11,450,000
Less, accumulated depreciation	(8,351,000)	(7,484,000)
	7,442,000	3,966,000
Total net property and equipment	219,182,000	70,146,000
Other assets	729,000	419,000
Total assets	$ 291,592,000	$ 109,383,000

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

PRIMEENERGY CORPORATION and SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS, December 31, 2006 and 2005

	2006	2005
LIABILITIES and STOCKHOLDERS' EQUITY:		
Current liabilities:		
Accounts payable	$ 42,658,000	$ 14,642,000
Current portion of asset retirement and other long-term obligations	314,000	1,246,000
Current portion of deferred taxes liability	1,961,000	—
Accrued liabilities	22,030,000	8,606,000
Due to related parties	477,000	1,027,000
Total current liabilities	67,440,000	25,521,000
Long-term bank debt	136,460,000	28,050,000
Asset retirement obligations	6,314,000	2,216,000
Deferred income taxes	25,367,000	13,860,000
Total liabilities	235,581,000	69,647,000
Minority Interest	1,313,000	—
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 2006 and 2005	769,000	769,000
Paid in capital	11,024,000	11,024,000
Retained earnings	66,908,000	48,608,000
Accumulated other comprehensive income	3,976,000	—
	82,677,000	60,401,000
Treasury stock, at cost 4,478,145 common shares in 2006 and 4,367,155 in 2005	(27,979,000)	(20,665,000)
Total stockholders' equity	54,698,000	39,736,000
Total liabilities and stockholders' equity	$ 291,592,000	$ 109,383,000

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, 2006, 2005 and 2004

	2006	2005	2004
Revenue:			
Oil and gas sales	$ 61,924,000	$ 53,988,000	$ 43,967,000
Field service income	20,319,000	15,182,000	11,965,000
Administrative overhead fees	9,704,000	7,068,000	6,317,000
Loss on derivative instruments, net	—	(415,000)	—
Interest and other income	472,000	123,000	179,000
	92,419,000	75,946,000	62,428,000
Costs and expenses:			
Lease operating expense	21,040,000	18,573,000	14,939,000
Field service expense	15,796,000	12,791,000	10,939,000
Depreciation, depletion and amortization	14,437,000	11,274,000	12,156,000
General and administrative expense	12,400,000	10,493,000	7,536,000
Exploration costs	1,162,000	664,000	5,499,000
	64,835,000	53,795,000	51,069,000
Income from operations	27,584,000	22,151,000	11,359,000
Other income and expense:			
Less interest expense	2,091,000	1,531,000	1,136,000
Add gain on sale and exchange of assets	3,017,000	20,334,000	75,000
Income before provision for income taxes	28,510,000	40,954,000	10,298,000
Provision for income taxes	10,210,000	14,999,000	3,023,000
Net income	$ 18,300,000	$ 25,955,000	$ 7,275,000
Basic net income per common share	$ 5.52	$ 7.64	$ 2.04
Diluted net income per common share	$ 4.50	$ 6.27	$ 1.70

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, 2006, 2005 and 2004

	Common Stock Shares	Common Stock Amount	Additional Paid In Capital	Retained Earnings	Accumulated Other comprehensive Income	Treasury Stock	Total
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
Purchased 164,410 shares of common stock						(4,456,000)	(4,456,000)
Net Income				25,955,000			25,955,000
Balance at December 31, 2005	7,694,970	$ 769,000	$ 11,024,000	$ 48,608,000	$ —	$ (20,655,000)	$ 39,736,000
Purchased 110,990 shares of common stock						(7,314,000)	(7,314,000)
Net Income				18,300,000			18,300,000
Other comprehensive income, net of taxes					3,976,000		3,976,000
Balance as of December 31, 2006	7,694,970	$ 769,000	$ 11,024,000	$ 66,908,000	$ 3,976,000	$ (27,979,000)	$ 54,698,000

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, 2006, 2005 and 2004

	2006	2005	2004
Cash flows from operating activities:			
Net income	$ 18,300,000	$ 25,955,000	$ 7,275,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion on discounted liabilities	14,437,000	11,274,000	12,156,000
Dry hole and abandonment costs	510,000	262,000	5,499,000
Gain on sale of properties	(3,017,000)	(20,334,000)	(75,000)
Stock based compensation expense	1,313,000	—	—
Provision for deferred income taxes	11,557,000	6,230,000	3,358,000
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	(16,411,000)	(7,803,000)	(1,586,000)
(Increase) decrease in due from related parties	330,000	(985,000)	209,000
(Increase) decrease in inventories	(3,133,000)	—	—
(Increase) decrease in prepaid expenses	6,435,000	(7,181,000)	(111,000)
(Increase) decrease in other assets	(53,000)	(139,000)	(137,000)
Increase (decrease) in accounts payable	3,716,000	5,510,000	1,016,000
Increase (decrease) in accrued liabilities	(1,450,000)	5,385,000	(276,000)
Increase (decrease) in due to related parties	(552,000)	431,000	(333,000)
Net cash provided by operating activities	31,982,000	18,605,000	26,995,000
Cash flows from investing activities			
Capital expenditures, including exploration expense	(121,345,000)	(54,440,000)	(24,696,000)
Proceeds from sale of properties and equipment	3,017,000	46,796,000	75,000
Net cash used in investing activities	(118,328,000)	(7,644,000)	(24,621,000)
Cash flows from financing activities Purchase of stock for treasury	(7,314,000)	(4,456,000)	(2,474,000)
Increase in long-term bank debt and other long-term obligations	198,362,000	65,570,000	32,522,000
Repayment of long-term bank debt and other long-term obligations	(91,168,000)	(67,432,000)	(29,837,000)
Net cash provided by (used in) financing activities	99,880,000	(6,318,000)	211,000
Net increase in cash and cash equivalents	13,534,000	4,643,000	2,585,000
Cash and cash equivalents at the beginning of the period	11,119,000	6,476,000	3,891,000
Cash and cash equivalents at the end of the period	$ 24,653,000	$ 11,119,000	$ 6,476,000
Supplemental disclosures:			
Income taxes paid during the year	$ 5,713,000	$ 5,076,000	$ —
Net income tax refunds received during the year	$ —	$ —	$ 172,000
Interest paid during the year	$ 2,091,000	$ 1,531,000	$ 953,000

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

PRIMEENERGY CORPORATION and SUBSIDIARIES

NOTES to 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 1,545 wells and owns non-operating interests in over 856 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. PEC also owns Prime Offshore L.L.C. (Prime Offshore) formerly F-W Oil Exploration LLC, 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 limited partnerships and 2 trusts (collectively, the "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. 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. 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 developed 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.

Capitalization of Interest:

Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated and successful.

Impairment of Long-Lived Assets:

The Company reviews Long-Lived Assets, including oil and gas properties, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows. The amount of impairment of oil and gas properties was $29,000 and $1,809,000 recorded for the periods ended December 31, 2006 and 2005, respectively, and is included in the results of operations in depreciation, depletion and amortization.

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 and 149 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 Pronouncements:

In February 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 155 "Accounting for Certain Hybrid Financial Instruments-an amendment of FASB Statements No. 133 and 140." SFAS No. 155 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 140, "Accounting for Transfers for Servicing of Financial Assets and Extinguishments of Liabilities," and also resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, "Application of Statement 133 to Beneficial Interests in Securitized Financial Assets." SFAS No. 155 was issued to eliminate the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for in a similar fashion, regardless of the instrument's form. The Company does not believe that its financial position, results of operations or cash flows will be impacted by SFAS No. 155 as the Company does not currently hold any hybrid financial instruments.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109." This interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS NO. 109, "Accounting for Income Taxes". FIN NO. 48 prescribes a two-step process for accounting for income tax uncertainties. First, a threshold condition of "more likely than not" should be met to determine whether any of the benefit of the uncertain tax position should be recognized in the financial statements. If the recognition threshold is met, FIN 48 provides additional guidance on measuring the amount of the uncertain tax position. Guidance is also provided regarding derecognition, classification, interest and penalties, interim period accounting, transition and disclosure of these uncertain tax positions. This Interpretation is effective for fiscal years beginning after December 15, 2006, and we will adopt it in the first quarter of 2007. We do not expect the adoption of Interpretation No. 48 to have a material impact on our financial statements and related disclosures.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by U.S. generally accepted accounting principles (GAAP) to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) NO. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. No new fair value measurements are prescribed, and SFAS No. 157 is intended to codify the several definitions of fair value included in various accounting standards. However, the application of this Statement may change current practices for certain companies. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating what impact SFAS No. 157 may have on its financial position, results of operations or cash flows.

In September 2006, the FASB issued No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)." SFAS No. 158 requires recognition of the funded status of a benefit plan in the Company's balance sheet and the recognition through other comprehensive income of gains, losses, prior service costs and credits, net of tax, arising during the period but not included as a component of periodic benefit cost. In addition, the measurement date of plan assets and obligations must be the Company's balance sheet date. Additional disclosures in the notes to the financial statements will also be required and guidance is prescribed regarding the selection of discount rates to be used in measuring the benefit obligation. For public companies, the effective date of SFAS No. 158 is as of the end of the fiscal year ending after December 15, 2006. The effective date of new measurement date provision is for fiscal years ending after December 15, 2008. The Company does not believe that its financial position, results of operations or cash flows will be impacted by SFAS No. 158 as the Company does not currently have defined benefit pension or post retirement plans.

In September 2006, the SEC Staff issued Staff Accounting Bulletin (SAB) No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," in an effort to address diversity in the accounting practices of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB No. 108, the two methods used for quantifying the effects of financial statement errors were the "roll-over" and "iron curtain" methods. Under the "roll-over" method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. On the other hand, the "iron curtain" method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB No. 108 establishes a "dual approach" which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures'. Public companies are required to record the cumulative effect of initially adopting the "dual approach" method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. The Company is currently evaluating the impact SAB No. 108 may have on its financial position, results of operations and cash flows.

In February 2007, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 159, "*The Fair Value Option for Financial Assets and Financial Liabilities*" ("SFAS 159"). This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this Statement permits all entities to choose to measure eligible items at fair value at specified election dates. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. We have not determined the effect, if any, the adoption of this statement will have on our financial position or results of operations .

2. Significant Acquisitions and Dispositions

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 $526,000 in 2006, $1,217,000 in 2005. 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.

In August 2005, the Company completed a transaction involving its interests in certain offshore Gulf of Mexico properties effective April 1, 2005 (the "Partners transaction"). Prime Offshore L.L.C. (Prime Offshore) formerly, F-W Oil Exploration L.L.C., a subsidiary of the Company, entered into a limited partnership agreement (the "Partners Agreement"), wherein Prime

Offshore is the General Partner of FWOE Partners L.P. ("Partners") formed for the acquisition, development and operation of oil and gas properties and pipelines, equipment, facilities and fixtures appurtenant thereto, in off-shore Gulf of Mexico (the "Properties"). Prior to entering into the Partners Agreement, Prime Offshore had distributed interests in the Properties to the minority shareholders of Prime Offshore and the Company purchased all of the outstanding shares of such minority shareholders for $250,000, resulting in the Company's 100% ownership of Prime Offshore.

Prime Offshore contributed all of its interest in the Properties to Partners in exchange for an initial 20% General Partner interest in Partners and a cash distribution of $43.2 million. Partners purchased the interests previously distributed to the former minority shareholders for $27.7 million. The entire $70.9 million expended by Partners was funded by a cash contribution by the Limited Partner. The cash distribution includes adjustments for estimated net revenues from the effective date of April 1, 2005, estimated capital expenditures and other typical closing adjustments.

In July 2005, the Company completed the sale of certain leasehold and exploration rights in prospects generated in the Company's onshore Texas 2-d Seismic Exploration Program in exchange for a cash payment of $3.5 million.

3. Additional Balance Sheet Information

Accounts receivable at December 31, 2006 and 2005, consisted of the following:

	December 31, 2006	December 31, 2005
Joint interest billing	$ 13,054,000	$ 3,904,000
Trade receivables	2,367,000	1,922,000
Oil and gas sales	8,764,000	9,183,000
Income tax receivable	3,023,000	—
Other	5,912,000	2,154,000
	33,120,000	17,163,000
Less: allowance for doubtful accounts	(150,000)	(605,000)
Total	$ 32,970,000	$ 16,558,000

Accrued Liabilities at December 31, 2006 and 2005, consisted of the following:

	December 31, 2006	December 31, 2005
Compensation and related expenses	$ 1,584,000	$ 1,632,000
Property costs	16,188,000	1,961,000
Income tax	270,000	4,275,000
Other	3,988,000	738,000
Total	$ 22,030,000	$ 8,606,000

4. Property and Equipment

Total interest costs incurred during 2006 was $4,555,000. Of this amount, the Company capitalized $2,464,000. Capitalized interest is included as part of the cost of oil and gas properties. The capitalized rates are based upon the Company's weighted-average cost of borrowings used to finance the expenditures.

5. Long-Term Bank Debt — Debt

The Company currently has credit facilities totaling $360 million, consisting of a $200 million credit facility through Guaranty Bank (the offshore facility) and a $160 million credit facility through a syndicate of banks led by Guaranty Bank (the onshore facility). The credit facilities mature in 2008 and 2009 . Availability under the credit facilities is based on the loan value assigned to Prime's oil and gas properties. At December 31, 2006, the borrowing bases and outstanding balances were $82 million under the onshore credit facility at a weighted average interest rate of 8.18%, and $54.5 million under the offshore credit facility at a weighted average interest rate of 10.15%. Currently, the borrowing base and outstanding balance under the onshore credit facility is $82 million and $72 million, respectively, and the borrowing base and outstanding balance under the offshore credit facility is $74.5 million.

The determination of the Borrowing Base is made by the lenders taking into consideration the estimated value of Prime's oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. This process involves reviewing Prime's estimated proved reserves and their valuation. The Borrowing Base is redetermined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redeterminations. In addition, Prime and the lenders each have discretion at any time to have the Borrowing Base redetermined. A revision to Prime's reserves may prompt such a request on the part of the lenders, which could possibly result in a reduction in the Borrowing Base and availability under the credit facilities. If outstanding borrowings under either of the credit facilities exceed the applicable portion of the Borrowing Base, Prime would be required to repay the excess amount within a prescribed period. If we are unable to pay the excess amount, it would cause an event of default.

The credit facilities include terms and covenants that require 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.

The credit facilities are collateralized by substantially all of the Company's assets. The Company is required to mortgage, and grant a security interest in, consolidated proved oil and gas properties. Prime also pledged the stock of several subsidiaries to the lenders to secure the credit facilities.

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. The future minimum lease payment for the operating leases are as follows.

	Operating Leases
2007	$ 553,000
2008	529,000
2009	525,000
2010	30,000
Thereafter	—
Total minimum payments	$ 1,637,000

Asset Retirement Obligation:

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2006 and 2005 is as follows:

	2006	2005
Asset retirement obligation — beginning of period	$ 2,594,000	$ 390,000
Liabilities incurred	3,033,000	1,456,000
Liabilities settled	(348,000)	(116,000)
Accretion expense	125,000	80,000
Revisions in estimated liabilities	1,036,000	784,000
Asset retirement obligation — end of period	$ 6,440,000	$ 2,594,000

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 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. As of December 31, 2006, the affiliated Partnerships have established cash reserves in excess of their debts and liabilities and the Company believes these reserves will be sufficient to satisfy Partnership 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 less than $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 $50,000.

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, 2006 and 2005, 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, 2006, 2005 and 2004 are as follows:

	2006	2005	2004
Federal:			
Current	$ (1,814,000)	$ 8,011,000	$ 187,000
Deferred	11,408,000	5,429,000	2,074,000
State:			
Current	467,000	803,000	266,000
Deferred	149,000	756,000	496,000
Total	$ 10,210,000	$ 14,999,000	$ 3,023,000

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

	December 31, 2006	December 31, 2005
Current assets:		
Compensation and benefits	$ 56,000	$ 226,000
Allowance for doubtful accounts	252,000	229,000
Total current deferred income tax assets	$ 308,000	$ 455,000
Current liabilities:		
Unrealized gain on hedging transactions	$ 2,270,000	$ —
Net current deferred tax liability (Asset)	$ 1,962,000	$ (455,000)
Noncurrent assets:		
Alternative minimum tax credits	$ 7,328,000	—
Net Operating Loss Carryfowards	903,000	—
Percentage Depletion Carryfowards	351,000	—
Total noncurrent assets	$ 8,582,000	$ —
Noncurrent liabilities:		
Basis differences relating to partnerships	$ 1,213,000	$ 835,000
Depletion and depreciation	32,639,000	13,025,000
Unrealized gain on hedging transactions	96,000	—
Total noncurrent liabilities	$ 33,948,000	$ 13,860,000
Net noncurrent deferred income tax liabilities	$ 25,366,000	$ 13,860,000

The total provision for income taxes for the years ended December 31, 2006, 2005 and 2004 varies from the federal statutory tax rate as a result of the following:

	December 31, 2006	December 31, 2005	December 31, 2004
Expected tax expense	$ 9,693,000	$ 14,013,000	$ 3,501,000
State income tax, net of federal benefit	411,000	1,029,000	503,000
Percentage depletion	(352,000)	(429,000)	(811,000)
Executive Compensation	542,000	467,000	—
Other, Net	(84,000)	(81,000)	(170,000)
Tax expense	$ 10,210,000	$ 14,999,000	$ 3,023,000

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Differences relating to oil and gas properties owned through Prime Offshore are reflected under "Depletion and Depreciation", while basis differences relating to the managed partnerships are reflected under "Basis differences relating to managed partnerships" Due primarily to the current deduction of intangible drilling costs, the company will have a federal net operating loss (NOL) in 2006, which will be carried back to the 2004 and 2005 tax years resulting in a refund of $2,623,000. As intangible drilling costs are a preference item for the alternative minimum tax (AMT), the Company will have a current year liability based on the AMT. Absent the NOL carryback, the Company would have a current federal income tax expense of $809,000. The result of combining these amounts is a current tax benefit of $1,814,000.

The NOL carryback to 2004 and 2005 will reduce the Company's regular tax to zero, so that the remaining liability for those years will be based solely on the amount of the AMT. The Company will get AMT credit carryforwards for the amount of such liability.

In 2006, $2,366,000 of deferred tax relating to unrealized gains on hedging transactions was charged directly to shareholder's equity. 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, it creates 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 2006.

Oil Purchasers:		Gas Purchasers:	
Texon Distributing L.P.	36%	Unimark LLC	25%
Plains All American Inc.	38%	Cokinos Energy Corporation	23%
TEPPCO Crude Oil, L.L.C.	11%		

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. Derivative Instruments and Hedging Activity:

The Company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. At December 31, 2006, the Company had three cash flow hedges open: two natural gas price swap arrangements and one crude oil collar arrangement. At December 31, 2006, $6.34 million ($3.98 million net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income, along with a $6.08 million short-term derivative receivable and a $260,000 thousand long-term derivative receivable. The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives, is recorded currently in earnings as a component of oil and gas sales.

As of December 31, 2006, natural gas price swaps cover 3,080 Mmcf of production at a weighted average price of $9.22. The oil price three-way collar covers 206 Mbbl of production at a floor price of $65.00, a ceiling of $79.25 and a third-tier call of $100.

Assuming no change in commodity prices, after December 31, 2006, the Company would expect to reclassify to the Statement of Operations, over the next 12 months, $3.89 million in after-tax income associated with commodity hedges. This reclassification represents the net short-term receivable associated with open positions currently not reflected in earnings at December 31, 2006 related to anticipated 2007 production.

12. 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 $526,000 in 2006 and $1,217,000 in 2005.

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, 2006 and 2005, primarily represents receipts collected by the Company as agent, for oil and gas sales net of expenses. The amount of such receipts payable to the affiliated Partnerships was $477,000 and $1,246,000 at December 31, 2006 and 2005, respectively. Receivables from related parties consist of reimbursable general and administrative costs, lease operating expenses and reimbursements for property development, and related costs. Due from related parties was $655,000 and $985,000 as of December 31, 2006 and 2005 respectively. Treasury stock purchases in 2006 and 2005 included shares acquired from related parties. Purchases from related parties include a total of 40,259 shares purchased for a total consideration of $2,623,564 in 2006 and 92,432 shares purchased for a total consideration of $2,098,640 in 2005.

During 2005, the Company purchased certain equipment from a managing member of FWOE Exploration L.L.C. for $1,200,000.

13. Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents includes $2,526,000 and $1,797,000 at December 31, 2006 and 2005, respectively, of cash primarily pertaining to unclaimed royalty payments. There were corresponding accounts payable recorded at December 31, 2006 and 2005 for these liabilities.

14. 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 $366,000 and $319,500 in 2006 and 2005, respectively.

15. 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, 2006		
	Net Income	Number of Shares	Per share Amount
Net income per common share	$ 18,300,000	3,314,003	$ 5.52
Effect of dilutive securities:			
Options	—	755,682	
Diluted net income per common share	$ 18,300,000	4,069,685	$ 4.50

	Year ended December 31, 2005		
	Net Income	Number of Shares	Per share Amount
Net income per common share	$ 25,955,000	3,397,820	$ 7.64
Effect of dilutive securities:			
Options		742,589	
Diluted net income per common share	$ 25,955,000	4,140,409	$ 6.27

	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

16. Selected Quarterly Financial Information (Unaudited)

2006	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Revenue	$ 21,177,000	$ 24,842,000	$ 24,331,000	$ 22,752,000
Operating income	3,879,000	9,050,000	7,704,000	6,951,000
Net income	2,393,000	6,609,000	5,320,000	3,978,000
Net income per common share	$ 0.74	$ 2.02	$ 1.61	$ 1.20
Diluted net income per common share	$ 0.60	$ 1.64	$ 1.31	$ .98

2005	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Revenue	$ 22,967,000	$ 19,293,000	$ 17,595,000	$ 16,091,000
Operating income	9,344,000	4,426,000	4,293,000	4,088,000
Net income	6,827,000	14,554,000	2,315,000	2,259,000
Net income per common share	$ 2.02	$ 4.32	$ 0.68	$ 0.65
Diluted net income per common share	$ 1.65	$ 3.54	$ 0.56	$ 0.54

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION and SUBSIDIARIES

SUPPLEMENTARY INFORMATION

PRIMEENERGY CORPORATION and SUBSIDIARIES

CAPITALIZED COSTS RELATING to OIL and GAS PRODUCING ACTIVITIES

December 31, 2006, 2005 and 2004

(Unaudited)

	2006	2005	2004
Developed oil and gas properties	$ 284,698,000	$ 125,248,000	$ 95,018,000
Undeveloped oil and gas properties	5,047,000	6,166,000	13,149,000
	289,745,000	131,414,000	108,167,000
Accumulated depreciation, depletion and valuation allowance	78,005,000	65,234,000	60,098,000
Net capitalized costs	$ 281,740,000	$ 66,180,000	$ 48,069,000

COSTS INCURRED in OIL and GAS PROPERTY ACQUISITION,

EXPLORATION and DEVELOPMENT ACTIVITIES

Years ended December 31, 2006, 2005 and 2004

(Unaudited)

	2006	2005	2004
Acquisition of Properties Developed	$ 1,408,000	$ 1,569,000	$ 2,038,000
Undeveloped	$ 5,047,000	$ 6,166,000	$ 10,058,000
Exploration Costs	$ 17,429,000	$ 664,000	$ 5,499,000
Development Costs	$ 135,609,000	$ 44,745,000	$ 7,101,000

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, 2006, 2005 and 2004

(Unaudited)

	2006	2005	2004
Future cash inflows	$ 641,744,000	$ 618,621,000	$ 378,639,000
Future production and development costs	(267,243,000)	(256,672,000)	(167,155,000)
Future income tax expenses	(86,915,000)	(109,571,000)	(62,819,000)
Future net cash flows	287,586,000	252,378,000	148,665,000
10% annual discount for estimated timing of cash flow	(88,963,000)	(106,899,000)	(54,254,000)
Standardized measure of discounted future net cash flows	$ 198,623,000	$ 145,479,000	$ 94,411,000

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, 2006, 2005 and 2004

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2006, 2005 and 2004:

For Year Ended December 31,	2006	2005	2004
Sales of oil and gas produced, net of production costs	$ (40,884,000)	$ (35,415,000)	$ (29,028,000)
Net changes in prices and production costs	(55,367,000)	47,729,000	22,178,000
Extensions, discoveries and improved recovery	147,292,000	64,175,000	18,792,000
Revisions of previous quantity estimates	(1,742,000)	32,060,000	9,904,000
Reserves purchased, net of development costs	383,000	927,000	2,238,000
Net change in development costs	1,870,000	7,914,000	(14,000)
Reserves sold	—	(64,246,000)	—
Accretion of discount	20,855,000	13,391,000	6,459,000
Net change in income taxes	(13,427,000)	(23,567,000)	(9,656,000)
Changes in production rates (timing) and other	(5,836,000)	8,100,000	286,000
Net change	53,144,000	51,068,000	21,159,000
Standardized measure of discounted future net cash flow:			
Beginning of year	145,479,000	94,411,000	73,252,000
End of year	$ 198,623,000	$ 145,479,000	$ 94,411,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION and SUBSIDIARIES

RESERVE QUANTITY INFORMATION

Years ended December 31, 2006, 2005 and 2004

(Unaudited)

	2006		2005		2004	
	Oil (bbls.)	Gas (Mcf)	Oil (bbls.)	Gas (Mcf)	Oil (bbls.)	Gas (Mcf)
Proved developed and undeveloped reserves:						
Beginning of year	3,687,000	44,944,000	2,932,000	44,870,000	2,905,000	39,005,000
Extensions, discoveries and improved recovery	812,000	31,394,000	807,000	11,087,000	42,000	7,268,000
Revisions of previous estimates	91,000	(1,602,000)	373,000	5,929,000	268,000	2,806,000
Purchases	17,000	192,000	25,000	517,000	88,000	929,000
Reserves sold	—	—	(89,000)	(12,701,000)	—	—
Production	(379,000)	(5,695,000)	(361,000	(4,758,000)	(371,000)	(5,138,000)
End of year	4,228,000	69,233,000	3,687,000	44,944,000	2,932,000	44,870,000
Proved developed reserves	4,009,000	66,754,000	3,504,000	43,976,000	2,926,000	37,728,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION and SUBSIDIARIES

RESULTS of OPERATIONS from OIL and GAS PRODUCING ACTIVITIES

Years ended December 31, 2006, 2005 and 2004

(Unaudited)

	2006	2005	2004
Revenue:			
Oil and gas sales	$ 61,924,000	$ 53,988,000	$ 43,967,000
Costs and expenses:			
Lease operating expense	21,040,000	18,573,000	14,939,000
Exploration costs	1,162,000	664,000	5,499,000
Depreciation and Depletion	12,771,000	10,125,000	11,021,000
Income tax expense	9,652,000	9,604,000	3,023,000
	44,625,000	38,966,000	34,482,000
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 17,299,000	$ 15,022,000	$ 9,485,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION and SUBSIDIARIES

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 SFASW 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.

Corporate Information

Auditors

Pustorino, Puglisi & Co., LLP
New York, New York

Counsel

James F. Gilbert
Dallas, Texas

Commercial Bankers

Guaranty Bank, FSB
Houston, Texas

Transfer Agent

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Annual Meeting

June 7, 2007, at 8:00 a.m. CDT
Hilton Midland Plaza
117 West Wall Street
Midland, Texas 79701

NASDAQ Symbol

PNRG

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Stamford, Connecticut 06901
(203) 358-5700

Operating Offices

Prime Offshore L.L.C.

Houston, Texas

Prime Operating Company

Houston, Texas
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 2006 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:

PrimeEnergy Corporation
One Landmark Square
Stamford, CT 06901
Attn: Investor Relations

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Officers

Charles E. Drimal, Jr.
President and Chief Executive Officer

James F. Gilbert
Secretary

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

Directors

Beverly A. Cummings
PrimeEnergy Corporation

Charles E. Drimal, Jr.
PrimeEnergy Corporation

Matthias Eckenstein
Architect and Developer
Basel, Switzerland

H. Gifford Fong
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Clint Hurt
President
Clint Hurt Associates, Inc.
Oil and Gas Exploration
Midland, Texas

Jan K. Smeets
Private Investor
Larchmont, New York

END

PrimeEnergy Corporation
2006 Annual Report