

PRIMEENERGY CORP  
Form 10-K/A  
March 24, 2009

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549

FORM 10-K/A  
(Amendment No. 1)

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2007

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

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

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  No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer.

Large Accelerated Filer  Accelerated Filer  Non-Accelerated Filer  Smaller Reporting Company

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

Yes  No

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 \$36,534,839.

The number of shares outstanding of each class of the Registrant's Common Stock as of March 21, 2008, was: 3,075,079 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 2008, are incorporated by reference in Part III hereof.

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EXPLANATORY NOTE

This Amendment No. 1 on Form 10-K/A (the “Form 10-K/A”) amends the Annual Report on Form 10-K for the year ended December 31, 2007 (the “2007 Annual Report”) filed by PrimeEnergy Corporation. (the “Company”) originally filed with the Securities and Exchange Commission on March 27, 2008. The Form 10-K/A includes amended and restated consolidated financial statements and related financial information for the years ended December 31, 2007, 2006 and 2005, including the financial results in each of the quarterly periods in 2007 and 2006. This information is disclosed in Notes 2 and 17 to the consolidated financial statements.

The restatement provides detail of the change in accounting method from proportionate consolidation of partnerships that the Company controls to the full consolidation method and the recognition of gain on the sale of assets to a partnership in which the Company acquired a twenty percent non-controlling interest.

The following items are included in this amendment:

PART I -

ITEM 1. Business  
ITEM 2. Properties

PART II -

ITEM 6. Selected Financial Data  
ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations  
ITEM 8. Financial Statements and Supplemental Data

All other information contained in the original Form 10-K remains unchanged. However, the entire report with all Items is included in this Form 10-K/A-1 for the convenience of the reader. This Amendment No.1 on Form 10-K/A does not reflect events occurring after the filing of our Annual Report on Form 10-K on March 27, 2008 or include, or otherwise modify or update, the disclosure contained therein in any way except as expressly indicated above.

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PrimeEnergy Corporation

FORM 10-K ANNUAL REPORT

For the Fiscal Year Ended

December 31, 2007

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 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, 2007, the Company had net capitalized costs related to oil and gas properties of \$237.9 million, including \$4.5 million of undeveloped properties. Total expenditures for the acquisition, exploration and development

of the Company's properties during 2007 were \$109.8 million of which \$633,000 related to exploration costs expensed during 2007. Proved reserves as of December 31, 2007, were 101 BCFe of gas which consisted of 92% proved developed reserves and 8% proved undeveloped reserves.

For 2008 we have budgeted \$60 million for exploration and development in our core operating areas. As of March, 2008, the Company has committed approximately \$11 million on wells in these areas that have been spudded since January 1, 2008.

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### Significant 2007 activity

During 2007, we participated in drilling a total of 31 gross wells, 30 successful wells and 1 dry hole.

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 1,580 oil and gas wells, 417 through the Houston office, 219 through the Midland office, 446 through the Oklahoma City office and 498 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 2,680. 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.



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### 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.



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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.

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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.	30%
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Plains All American Inc.	54%
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Gas Purchasers:

Unimark LLC	12%
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Cokinos Energy Corporation	57%
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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.

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### 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:

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- 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.

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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 Sturgeon 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.

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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 2008, the Company had 233 full-time and 12 part-time employees, 20 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 197 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

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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.

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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, geophysical, 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.

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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.

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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 1 B. 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.

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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 three years ended December 31, 2007.

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil	--	--	—	—	1	.500
Gas	--	--	5	3.750	11	3.510
Dry	1	.375	1	.400	1	1.000
Development:						
Oil	30	13.88	41	22.141	17	8.500
Gas	--	--	28	11.664	15	7.790
Dry	--	--	—	—	4	2.410
Total:						
Oil	30	13.88	41	22.141	18	9.000
Gas	--	--	33	15.414	26	11.300
Dry	1	.375	1	.400	5	3.410
	31	14.255	75	37.955	49	23.710

## Oil and Gas Production

As of December 31, 2007, 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	926	365
Gas Wells	1,186	517
Producing Acres	315,640.83	106,589.27

(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 three years ended December 31, 2007. "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.

	2007	2006	2005
Oil (barrels)	561,000	456,000	443,000
Gas (Mcf)	11,312,000	6,411,000	5,641,000

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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 three years ended December 31, 2007.

	2007	2006	2005
Average sales price per barrel	\$ 66.94	61.10	52.75
Average sales price Per Mcf	\$ 7.50	6.83	7.44
Average production costs per net equivalent barrel			
(1)	\$ 14.24	16.62	16.80

(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, 2007. "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.

State	Leasehold Interests		Mineral Interests		Royalty Interests	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Colorado	22	11	799	23	--	--
Gulf of Mexico	58,837	43,454	--	--	--	--
Montana	--	--	13,984	59	786	5
Nebraska	--	--	2,553	331	--	--
North Dakota	--	--	640	1	--	--
Oklahoma	5,942	3,754	320	1	--	--
Texas	8,388	5,138	680	16	--	--
New Mexico	116	38	--	--	--	--
West Virginia	603	603	--	--	--	--
Wyoming	1,000	125	5,043	35	140	35
TOTAL	74,907	53,123	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 three years ended December 31, 2007. 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



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As of 12-31	Proved Developed		Proved Undeveloped		Total	
	Oil (bbls)	Gas (Mcf)	Oil (bbls)	Gas (Mcf)	Oil (bbls)	Gas (Mcf)
2005	4,529,000	54,373,000	183,000	968,000	4,712,000	55,341,000
2006	4,986,000	75,434,000	219,000	2,479,000	5,205,000	77,913,000
2007	5,640,000	58,814,000	952,000	2,598,000	6,592,000	61,412,000

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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 three years ended December 31, 2007, are summarized as follows (figures rounded):

As of 12-31	Proved Developed		Proved Undeveloped		Future Net Revenue	Total		Standardized Measure of Discounted Cash flow
	Future Net Revenue	Present Value Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue		Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	
2005	\$ 435,525,000	244,817,000	12,510,000	6,663,000	448,035,000	251,480,000	77,991,000	173,489,000
2006	\$ 409,525,000	269,139,000	13,836,000	7,077,000	423,361,000	276,216,000	60,028,000	216,188,000
2007	\$ 449,372,000	266,405,000	60,392,000	21,062,000	509,764,000	287,467,000	62,007,000	225,460,000

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, 2007 and 2006 was \$6.79 and \$5.62 per MMBTU, respectively. The range of spot prices during the year 2007 was a low of \$5.35 and a high of \$8.98 and the average was \$6.97. The range during the first quarter of 2008 has been from \$5.75 to \$9.87, with an average of \$8.51. The recent futures market prices have traded above \$9.09 per MMBTU.

The NYMEX price for oil at December 31, 2007 and 2006, was \$96.01 and \$61.06 per barrel, respectively. The range of NYMEX prices during the year 2007 was a low of \$50.48 and a high of \$98.18 and the average was \$71.95. The range during the first quarter of 2008 has been from \$86.99 to \$110.33, with an average of \$97.09. The recent futures market prices have fluctuated around \$104.48.

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, 2008, 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.

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## District Information

The following table presents certain reserve, production and well information as of December 31, 2007.

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Offshore	Other	Total
Proved Reserves at Year End (Mmcfe)							
Developed	13,162	7,078	29,251	27,793	14,162	1,208	92,654
Undeveloped				8,309			8,309
Total	13,162	7,078	29,251	36,102	14,162	1,208	100,963
Average Daily Production (Mmcfe per day)	3	3	7	8	18	1	40
Gross Wells	732	505	734	324	21	81	2,397
Net Wells	377	180	280	106	11	15	969
Gross Operated Wells	498	332	446	219	17	68	1,580

## District Information

## Appalachian Region

Our Appalachian activities are concentrated primarily in West Virginia. In this region, our assets include a large acreage position and a high concentration of wells. At December 31, 2007, we had 732 wells (377 net), of which 498 wells are operated by us. There are multiple producing intervals that include the Big Lime, Injun, Blue Monday, Weir, Berea, Gordon and Devonian Shale formations at depths primarily ranging from 1,600 to 5,600 feet. Average net daily production in 2007 was 2,762 Mcfe. While natural gas production volumes from Appalachian reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of Appalachian reserves is relatively long. At December 31, 2007, we had 13.2 Bcfe of proved reserves (substantially all natural gas) in the Appalachian region, constituting 13% of our total proved reserves. This region is managed from our office in Charleston, West Virginia.

## Gulf Coast Region

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in Louisiana, southeast Texas and south Texas. This region is managed from our office in Houston. Principal producing intervals are in the Marg Tex, Wilcox, Pettit, Glenrose, Woodbine, San Miguel, Olmos, and Yegua formations at depths ranging from 3,000 to 12,500 feet. We had 504 wells (179 net) in the Gulf Coast region as of December 31, 2007, of which 332 wells are operated by us. Average daily production in 2007 was 3,172 Mcfe. At December 31, 2007, we had 7.1 Bcfe of proved reserves (66% natural gas) in the Gulf Coast region, which

represented 7% of our total proved reserves.

#### Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. As of December 31, 2007, we had 734 wells (280 net) in the Mid-Continent area, of which 446 wells are operated by us. Principal producing intervals in the Mid-Continent are in the Roberson, Avant, Skinner, Sycamore, Bromide, McLish, Hunton, Mississippian, Oswego, Red Fork, and Chester formations at depths ranging from 1,100 to 10,500 feet. Average net daily production in 2007 was 7,675 Mcfe. At December 31, 2007, we had 29.3 Bcfe of proved reserves (60% natural gas) in the Mid-Continent area, or 29% of our total proved reserves. This region is managed from our office in Oklahoma City.

#### West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas and New Mexico. As of December 31, 2007, we had 324 wells (106 net) in the West Texas area, of which 219 wells are operated by us. Principal producing intervals in the West Texas are in the Spraberry, Wolfcamp and San Andres formations at depths ranging from 5,500 to 12,500 feet. Average net daily production in 2007 was 8,492 Mcfe. At December 31, 2007, we had 36.1 Bcfe of proved reserves (33% natural gas) in the West Texas area, or 36% of our total proved reserves. This region is managed from our office in Midland, Texas.

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## Offshore Gulf of Mexico

Our development, exploitation, exploration and production activities in the Offshore Gulf of Mexico are primarily concentrated in the western gulf area in shallow water. This region is managed from our office in Houston. Principal producing intervals are in the Pleistocene to Miocene formations at depths ranging from 750 to 12,500 feet. We had 21 wells (11 net) in the Offshore Gulf of Mexico region as of December 31, 2007, of which 17 wells are operated by us. Average daily production in 2007 was 18,229 Mcfe. At December 31, 2007, we had 14.2 Bcfe of proved reserves (substantially all natural gas) in the Offshore Gulf of Mexico region, which represented 14% of our total proved reserves.

## Acreage subject to Expiration in the next three years

State	2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net
GULF OF MEXICO	11,520	8,640	12,757	8,894	--	--
OKLAHOMA	1,660	1,455	799	799	85	85
TEXAS	319	112	3,520	2,974	877	877
NEW MEXICO	163	54	--	--	--	--
WEST VIRGINIA	121	121	--	--	--	11
COLORADO	--	--	--	--	22	11
TOTAL	13,783	10,382	17,077	12,668	1,544	984

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

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## PART II

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

The Company's Common Stock is traded in the NASDAQ Stock Market, trading symbol "PNRG". The high and low bid quotations for each quarterly period during the two years ended December 31, 2007, were as follows:

2007	High	Low	2006	High	Low
First Quarter	\$ 64.97	\$ 50.10	First Quarter	\$ 83.42	\$ 48.83
Second Quarter	\$ 64.90	\$ 54.75	Second Quarter	\$ 86.75	\$ 66.35
Third Quarter	\$ 58.60	\$ 53.00	Third Quarter	\$ 81.26	\$ 59.09
Fourth Quarter	\$ 56.95	\$ 52.43	Fourth Quarter	\$ 72.98	\$ 64.05

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 21, 2008, was 746.

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 2,700,000 shares have been authorized, to date, under this program. Through December 31, 2007, we repurchased a total of 2,414,445 shares under this program for \$29,109,072 at an average price of \$12.06 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.

2007 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Program
January	40	\$ 60.00	365,854
February	2,986	55.15	362,868
March	19,478	54.24	343,390
April	3,000	55.05	340,390
May	8,000	55.00	332,390

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June	10,000	55.45	322,390
July	11,000	55.02	311,390
August	12,282	55.00	299,108
September	88	55.05	299,020
October	1	55.05	299,019
November	13,012	55.01	286,007
December	452	55.19	285,555
Total/Average/Remainder	80,339	\$ 54.89	



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## 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.

	2007	2006	2005	2004	2003
Revenues	\$ 156,146,000	101,823,000	87,224,000	62,379,000	46,673,000
Income from operations	\$ 26,690,000	35,904,000	44,721,000	11,385,000	8,982,000
Net income	\$ 7,920,000	18,708,000	23,604,000	7,275,000	5,702,000
Income per common share	\$ 2.50	5.65	6.95	2.04	1.56
Diluted net income per common share	\$ 2.02	4.60	5.70	1.70	1.31
Total assets	\$ 305,655,000	300,108,000	117,336,000	69,926,000	58,255,000
Long-term obligations	\$ 166,377,000	167,624,000	43,267,000	30,290,000	26,925,000
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, 2007, was \$95 million, compared to \$38 million in the prior year.

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 2008.

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 2007 was \$4.8 million. The Company expects to expend a similar amount in 2008.

The Company currently maintains two credit facilities totaling \$360 million, with a combined current borrowing base of \$153.4 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.

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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.

## Results of Operations:

## 2007 as compared to 2006

The Company had net income of \$7,920,000 in 2007 as compared to \$18,708,000 in 2006. The significant components of net income are discussed below.

Oil and gas sales were \$122,361,000 in 2007 as compared to \$71,650,000 in 2006. A chart summarizing oil and gas production and revenue is presented below.

	2007	2006	Increase (Decrease)
Barrels of Oil Produced	561,000	456,000	105,000

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Average Price Received (rounded)	\$	66.94	\$	61.10	\$	5.84
Oil Revenue	\$	37,553,000	\$	27,863,000	\$	9,690,000
Mcf of Gas Produced		11,312,000		6,411,000		4,901,000
Average Price Received (rounded)	\$	7.50	\$	6.83	\$	0.67
Gas Revenue	\$	84,808,000	\$	43,787,000	\$	41,021,000
Total Oil & Gas Revenue	\$	122,361,000	\$	71,650,000	\$	50,711,000

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Changes in Production are due to additional production from properties added throughout 2007. The increase in gas production is primarily related to our offshore properties and the increase in oil production is from our West Texas properties.

Field Service Income increased to \$24,340,000 in 2007 from \$20,357,000 in 2006. This increase reflects higher utilization of equipment during 2007 combined with rate increases.

Lease operating expenses increased by 37% to \$34,841,000 in 2007 as compared to \$25,337,000 in 2006. The difference is attributable to costs associated with properties added during 2007 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 decreased to \$12,349,000 in 2007 as compared to \$12,977,000 in 2006, reflecting reduced compensation expense.

Depreciation and depletion increased to \$64,507,000 in 2007 from \$14,370,000 in 2006. This increase is directly attributed to the majority of the Company's offshore properties coming on line during 2007.

Exploration costs of \$633,000 were incurred in 2007 as compared to \$1,162,000 in 2006.

Interest expense increased to \$11,062,000 in 2007 from \$2,091,000 in 2006 due to increased average outstanding debt. The average interest rates paid on outstanding borrowings subject to interest during 2007 and 2006 were 8.77% and 8.80% respectively. As of December 31, 2007 and 2006, the total outstanding borrowings were \$155,000,000 and \$136,460,000, respectively.

Income tax expense of \$3,832,000 in 2007 represents a 33% effective rate as compared to the effective rate of 36% in 2006. The primary reason for the lower effective rate was higher percentage depletion deductions. These deductions which create a permanent difference are more significant as a percentage of book income when book income is lower, as it was in 2007. Current tax expense in 2007 was \$1,227,000 with the remainder being attributable to an increase in the Company's deferred tax liability.

The current federal tax expense for 2007 is below the statutory rate because 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 2007 and 2006.

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2006 as compared to 2005

The Company had net income of \$18,708,000 in 2006 as compared to \$23,604,000 in 2005.

Oil and gas sales were \$71,650,000 in 2006 as compared to \$65,320,000 in 2005. A chart summarizing oil and gas production and revenue is presented below.

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

	2006	2005	Increase(Decrease)
Barrels of Oil Produced	456,000	443,000	13,000
Average Price Received (rounded)	\$ 61.10	\$ 52.75	\$ 8.35
Oil Revenue	\$ 27,863,000	\$ 23,370,000	\$ 4,493,000
Mcf of Gas Produced	6,411,000	5,641,000	770,000
Average Price Received (rounded)	\$ 6.83	\$ 7.44	\$ (0.61)
Gas Revenue	\$ 43,787,000	\$ 41,950,000	\$ 1,837,000
Total Oil & Gas Revenue	\$ 71,650,000	\$ 65,320,000	\$ 6,330,000

Field Service Income increased to \$20,357,000 in 2006 from \$15,226,000 in 2005. This increase reflects higher utilization of equipment during 2006 combined with rate increases.

Lease operating expenses increased by 9% to \$25,337,000 in 2006 as compared to \$23,241,000 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 \$12,977,000 in 2006 as compared to \$11,048,000 in 2005, reflecting increases in personnel costs and professional fees. The \$1,929,000 increase includes \$1,313,000 representing the fair market value of subsidiary stock issued to two key executives.

Depreciation and depletion increased to \$14,370,000 in 2006 from \$11,784,000 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.

Gain on sale and exchange of assets decreased to \$3,729,000 in 2006 from \$16,588,000 in 2005. This decrease reflects the non-recurring gain recognized during 2005 related to the following transaction. 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 offshore 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.

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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.

To record this transaction, the Company applied the guidance of EITF 86-29, Non monetary transactions: Magnitude of Boot and the Exceptions to the Use of Fair Value. In this transaction, the boot was significant (in excess of 25% of the fair value of the exchange), therefore, the transaction was treated as a monetary transaction with the assets recorded at fair value. The Company recorded proceeds of \$61.2 million consisting of cash of \$43.2 million and the fair market value of the General Partner interest of \$18.0 million. The fair market value of the General Partner interest was determined by calculating 20% of the total agreed value of all properties acquired by the Partners. The related properties had a book value of \$42.5 million resulting in a total gain of \$18.7 million, however in accordance with EITF 01-2, since the Company acquired a 20% interest in Partners the Company recognized a gain of \$15 million, representing 80% of the total gain. The Company uses the proportionate consolidation method of accounting for its interest in Partners under the Guidance of EITF 00-1 as related to the extractive industries since the Company does not control Partners.

Income tax expense of \$10,440,000 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.

### 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, 2007, a hypothetical 2.5% increase in the applicable interest rates would increase interest expense by approximately \$3,680,000.

#### 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.

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## 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 2008, 2009, 2010 and 2011 production as follows:

Contract Period	Volume In Mbbbl	Crude Oil Price Collar Weighted Average Price Floor/Ceiling/Third Tier (per Bbl)	Net Unrealized (Loss)/Gain (In thousands)
First Quarter 2008	23	\$65/ \$79.25/ \$100.00	
First Quarter 2008	51	\$ 60.00/ \$81.25	
First Quarter 2008	15	\$ 60.00/ \$78.00	
Second Quarter 2008	21	\$65/ \$79.25/ \$100.00	
Second Quarter 2008	51	\$ 60.00/ \$81.25	
Second Quarter 2008	15	\$ 60.00/ \$78.00	
Third Quarter 2008	20	\$65/ \$79.25/ \$100.00	
Third Quarter 2008	51	\$ 60.00/ \$81.25	
Third Quarter 2008	15	\$ 60.00/ \$78.00	
Fourth Quarter 2008	18	\$65/ \$79.25/ \$100.00	
Fourth Quarter 2008	51	\$ 60.00/ \$81.25	
Fourth Quarter 2008	15	\$ 60.00/ \$78.00	
Full Year 2008	346		\$ (2,779)
First Quarter 2009	51	\$ 60/ \$79.70	
First Quarter 2009	6	\$ 60/ \$77.75	
First Quarter 2009	12	\$ 65/ \$86.50	
Second Quarter 2009	17	\$ 60/ \$79.70	
Second Quarter 2009	38	\$ 60/ \$77.40	
Second Quarter 2009	2	\$ 60/ \$77.75	
Second Quarter 2009	12	\$ 65/ \$86.50	
Third Quarter 2009	57	\$ 60/ \$77.40	
Third Quarter 2009	12	\$ 65/ \$86.50	
Fourth Quarter 2009	57	\$ 60/ \$77.40	
Fourth Quarter 2009	12	\$ 65/ \$86.50	
Full Year 2009	276		\$ (1,463)
First Quarter 2010	51	\$ 65/ \$80.90	
First Quarter 2010	9	\$ 65/ \$84.14	
Second Quarter 2010	51	\$ 65/ \$80.90	
Second Quarter 2010	9	\$ 65/ \$84.14	
Third Quarter 2010	51	\$ 65/ \$80.90	
Third Quarter 2010	9	\$ 65/ \$84.14	
Fourth Quarter 2010	51	\$ 65/ \$80.90	

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Fourth Quarter 2010	9	\$	65/ \$84.14	
Full Year 2010	240			\$ (651)
First Quarter 2011	45	\$	65/ \$84.14	
Full Year 2011	45			\$ (41)

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At December 31, 2007, we had open natural gas price swap contracts covering our 2008 and 2009 production as follows:

Contract Period	Volume in Mmcf	Natural Gas Price Swaps	
		Weighted Average Price (per Mcf)	Net Unrealized Gain (In thousands)
First Quarter 2008	645	\$ 8.96	\$ 593
Second Quarter 2008	1,005	8.07	285
Third Quarter 2008	1,005	8.07	150
Fourth Quarter 2008	1,005	8.07	(175)
Full Year 2008	3,660	\$ 8.23	\$ 853
First Quarter 2009	975	\$ 9.76	\$ 463
Full Year 2009	975	\$ 9.76	\$ 463

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.

As of the end of the period covered by this Annual Report on Form 10-K, our principal executive officer and principal financial officer have evaluated the effectiveness of our “disclosure controls and procedures” (Disclosure Controls). Disclosure Controls, as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act), are procedures that are designed with the objective of ensuring that information required to be disclosed in our reports filed under the Exchange Act, such as this Annual Report, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. Disclosure Controls are also designed with the objective of ensuring that such information is accumulated and communicated to our management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.



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Our management, including the chief executive officer and chief financial officer, does not expect that our Disclosure Controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Based upon their controls evaluation, our chief executive officer and chief financial officer have concluded that our Disclosure Controls are effective at a reasonable assurance level.

### Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Our internal control over financial reporting is a process designed to provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition, transactions are executed in accordance with appropriate management authorization and accounting records are reliable for the preparation of financial statements in accordance with generally accepted accounting principles.

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. Management based this assessment on criteria for effective internal control over financial reporting described in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management believes that PrimeEnergy Corporation maintained effective internal control over financial reporting as of December 31, 2007.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this annual report.

There have been no significant changes in our internal controls over financial reporting during the fourth fiscal quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

### Item 9B. OTHER INFORMATION.

None.

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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 the Company's Annual Meeting of Stockholders to be held in June, 2008, which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2007, 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, 2008, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2007, 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, 2008, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2007, 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, 2008, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2007, 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, 2008, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2007, and which is incorporated herein by reference.



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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 (Incorporated by reference to Exhibit 10.3.2 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2007)  |
| 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 (Incorporated by reference to Exhibit 10.22.5 of PrimeEnergy Corporation  |

Form 10-K for the year ended December 31, 2006)

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 (Incorporated by reference to Exhibit 10.22.5.1 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)

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 (Incorporated by reference to Exhibit 10.23.2 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)

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10.23.3	Amended and Restated Security Agreement (Membership Pledge) by PrimeEnergy Corporation in favor of Guaranty Bank, FSB as Agent December 28, 2006 (Incorporated by reference to Exhibit 10.23.3 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
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 (Incorporated by reference to Exhibit 10.23.4 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
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 (Incorporated by reference to Exhibit 10.23.5 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
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 (Incorporated by reference to Exhibit 10.23.6 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
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 (Incorporated by reference to Exhibit 10.23.7 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
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 (Incorporated by reference to Exhibit 10.23.8 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
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 (Incorporated by reference to Exhibit 10.25 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
10.26	Credit Agreement dated June 29, 2006 between Prime Offshore L.L.C. and Guaranty Bank, FSB as Agent and a Lender (Incorporated by reference to Exhibit 10.26 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
10.26.1	Subordination Agreement effective as of June 29, 2006, between Prime Offshore L.L.C., PrimeEnergy Corporation, and Guaranty Bank, FSB (Incorporated by reference to Exhibit 10.26.1 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
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) (Incorporated by reference to Exhibit 10.27 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
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

(Incorporated by reference to Exhibit 10.27.1 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)

10.27.2 Pledge Agreement as of June 29, 2006, between Guaranty Bank, FSB and Prime Offshore L.L.C. (Incorporated by reference to Exhibit 10.27.2 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)

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. (Incorporated by reference to Exhibit 10.28 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)

10.29 Put Right Agreement effective as of June 29, 2006, by and among PrimeEnergy Corporation and Prime Offshore L.L.C. (Incorporated by reference to Exhibit 10.29 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)

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14	PrimeEnergy Corporation Code of Business Conduct and Ethics (Incorporated by reference to Exhibit 14 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)
21	Subsidiaries (filed herewith)
23	Consent of Ryder Scott & Company L.P. (filed herewith)
<u>31.1</u>	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)
<u>31.2</u>	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)
<u>32.1</u>	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith)
<u>32.2</u>	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith)

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

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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 16th day of March, 2009.

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 16th day of March, 2009.

/s/ CHARLES E.DRIMAL, JR.      Director and President;  
Charles E. Drimal, Jr.      The Principal Executive Officer

/s/ BEVERLY A. CUMMINGS      Director, Vice President and  
Beverly A. Cummings      Treasurer; The Principal  
Financial and Accounting Officer

Matthias Eckenstein      Director      /s/ CLINT HURT      Director  
Clint Hurt

/s/ H. GIFFORD FONG      Director      /s/ JAN K. SMEETS      Director  
H. Gifford Fong      Jan K. Smeets

/s/ THOMAS S.T. GIMBEL      Director  
Thomas S.T. Gimbel

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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, 2007 and 2006, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years ended December 31, 2007, 2006 and 2005. 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 Corporation is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits 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 Corporation'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, 2007 and 2006, and the consolidated results of its operations and cash flows for the years ended December 31, 2007, 2006 and 2005 in conformity with accounting principles generally accepted in the United States of America. As discussed in Note 2 to the financial statements, the 2007, 2006 and 2005 financial statements have been restated to correct certain misstatements.

PUSTORINO, PUGLISI & CO., LLP

New York, New York

March 26, 2008, except for Note 2, as to which the date is March 23, 2009

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## CONSOLIDATED BALANCE SHEETS, December 31, 2007 and 2006

	2007 Audited and Restated	2006 Audited and Restated
ASSETS:		
Current assets:		
Cash and cash equivalents	\$ 25,373,000	\$ 29,056,000
Restricted cash and cash equivalents	3,633,000	2,528,000
Accounts receivable, net	21,311,000	33,664,000
Due from related parties	32,000	429,000
Prepaid expenses	1,391,000	1,269,000
Derivative contracts	1,332,000	6,085,000
Inventory at cost	3,705,000	3,518,000
Deferred income tax	1,582,000	--
Total current assets	58,359,000	76,549,000
Property and equipment, at cost:		
Proved oil and gas properties at cost	378,908,000	293,837,000
Unproved oil and gas properties at cost	4,458,000	5,047,000
Less: Accumulated depletion and depreciation	145,514,000	83,563,000
	237,852,000	215,321,000
Field and office equipment	18,029,000	15,793,000
Less: Accumulated depreciation	9,820,000	8,351,000
	8,209,000	7,442,000
Total net property and equipment	246,061,000	222,763,000
Other assets	1,245,000	796,000
Total assets	\$ 305,665,000	\$ 300,108,000

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

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## CONSOLIDATED BALANCE SHEETS, December 31, 2007 and 2006

	2007 Audited and Restated	2006 Audited and Restated
LIABILITIES and STOCKHOLDERS' EQUITY:		
Current liabilities:		
Current bank debt	\$ 34,950,000	\$ --
Accounts payable	26,780,000	42,627,000
Current portion of asset retirement and other long-term obligations	1,065,000	345,000
Derivative liability short term	4,340,000	1,961,000
Accrued liabilities	10,032,000	22,098,000
Due to related parties	520,000	165,000
Total current liabilities	77,687,000	67,196,000
Long-term bank debt	120,050,000	136,460,000
Asset retirement obligations	16,936,000	6,890,000
Derivative liability long term	3,369,000	--
Deferred income taxes	26,022,000	24,274,000
Total liabilities	244,064,000	234,820,000
Minority interest	12,929,000	12,533,000
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 2007 and 2006	769,000	769,000
Paid in capital	11,024,000	11,024,000
Retained earnings	72,885,000	64,965,000
Accumulated other comprehensive income (loss), net	(3,618,000)	3,976,000
	81,060,000	80,734,000
Treasury stock, at cost 4,558,544 common shares in 2007 and 4,478,145 in 2006	(32,388,000)	(27,979,000)
Total stockholders' equity	48,672,000	52,755,000
Total liabilities and stockholders' equity	\$ 305,665,000	\$ 300,108,000

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

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## CONSOLIDATED STATEMENTS of OPERATIONS

for the years ended December 31, 2007, 2006 and 2005

	2007 Audited and Restated	2006 Audited and Restated	2005 Audited and Restated
Revenue:			
Oil and gas sales	\$ 122,361,000	\$ 71,650,000	\$ 65,320,000
Field service income	24,340,000	20,357,000	15,226,000
Administrative overhead fees	9,041,000	9,704,000	7,068,000
Loss on derivative instruments, net	--	--	(415,000)
Other income	404,000	112,000	25,000
	156,146,000	101,823,000	87,224,000
Costs and expenses:			
Lease operating expense	34,841,000	25,337,000	23,241,000
Field service expense	17,724,000	15,802,000	12,804,000
Depreciation, depletion and amortization	64,507,000	14,370,000	11,784,000
General and administrative expense	12,349,000	12,977,000	11,048,000
Exploration costs	633,000	1,162,000	664,000
	130,054,000	69,648,000	59,541,000
Add gain on sale and exchange of assets	598,000	3,729,000	16,588,000
Income from operations	26,690,000	35,904,000	44,271,000
Other income and expense:			
Less: Interest expense	11,062,000	2,091,000	1,531,000
Add interest income	852,000	508,000	153,000
Less: Minority interest	4,728,000	5,173,000	5,613,000
Income before provision for income taxes	11,752,000	29,148,000	37,280,000
Provision for income taxes	3,832,000	10,440,000	13,676,000
Net income	\$ 7,920,000	\$ 18,708,000	\$ 23,604,000
Basic net income per common share	\$ 2.50	\$ 5.65	\$ 6.95
Diluted net income per common share	\$ 2.02	\$ 4.60	\$ 5.70

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

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

CONSOLIDATED STATEMENT of STOCKHOLDERS' EQUITY  
(Audited and Restated)

for the years ended December 31, 2007, 2006 and 2005 (restated)

	Common Stock		Additional	Retained	Accumulated	Treasury	Total
	Shares	Amount	Paid In Capital	Earnings	Other Comprehensive Income (Loss)		
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				23,604,000			23,604,000
Balance at December 31, 2005	7,694,970	\$ 769,000	\$ 11,024,000	\$ 46,257,000	\$ --	\$ (20,665,000)	\$ 37,385,000
Purchased 110,990 shares of common stock						(7,314,000)	(7,314,000)
Net income				18,708,000			18,708,000
Other comprehensive income, net of taxes					3,976,000		3,976,000
Balance at December 31, 2006	7,694,970	\$ 769,000	\$ 11,024,000	\$ 64,965,000	\$ 3,976,000	\$ (27,979,000)	\$ 52,755,000
Purchased 80,399 shares of common stock						(4,409,000)	(4,409,000)
Net income				7,920,000			7,920,000
Other comprehensive income (loss), net of taxes					(7,594,000)		(7,594,000)
Balance as of December 31, 2007	7,694,970	\$ 769,000	\$ 11,024,000	\$ 72,885,000	\$ (3,618,000)	\$ (32,388,000)	\$ 48,672,000

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

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## CONSOLIDATED STATEMENTS of CASH FLOWS

for the years ended December 31, 2007, 2006 and 2005

	2007 Audited and Restated	2006 Audited and Restated	2005 Audited and Restated
Cash flows from operating activities:			
Net income	\$ 7,920,000	\$ 18,708,000	\$ 23,604,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion on discounted liabilities	64,507,000	14,370,000	11,784,000
Dry hole and abandonment costs	343,000	510,000	262,000
Gain on sale of properties	(598,000)	(3,729,000)	(16,588,000)
Non-cash incentive compensation expense	--	1,313,000	--
Provision for deferred income taxes	1,215,000	11,787,000	4,907,000
Minority interest in earnings of partnerships	4,728,000	5,173,000	5,613,000
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable	14,276,000	(15,480,000)	(6,406,000)
(Increase) decrease in due from related parties	1,306,000	484,000	(207,000)
(Increase) decrease in inventories	325,000	(3,136,000)	(6,000)
(Increase) decrease in prepaid expenses and other assets	(175,000)	6,449,000	(7,251,000)
Increase (decrease) in accounts payable	126,000	3,510,000	5,232,000
Increase (decrease) in accrued liabilities	53,000	(1,518,000)	5,217,000
Increase (decrease) in due to related parties	1,088,000	(620,000)	431,000
Net cash provided by operating activities	95,114,000	37,821,000	26,592,000
Cash flows from investing activities			
Capital expenditures, including exploration expense	(109,819,000)	(122,704,000)	(54,037,000)
Proceeds from sale of properties and equipment	598,000	3,729,000	43,050,000
Net cash used in investing activities	(109,221,000)	(118,975,000)	(10,987,000)
Cash flows from financing activities			
Purchase of stock for treasury	(4,409,000)	(7,314,000)	(4,456,000)
Increase in long-term bank debt and other long-term obligations	105,867,000	198,362,000	65,570,000
Repayment of long-term bank debt and other long-term obligations	(86,960,000)	(91,168,000)	(67,432,000)
Distribution to minority interest	(4,074,000)	(4,443,000)	(3,456,000)
Net cash provided by (used in) financing activities	10,424,000	95,437,000	(9,774,000)
Net increase(decrease) in cash and cash equivalents	(3,683,000)	14,283,000	5,831,000
Cash and cash equivalents at the beginning of the period	29,056,000	14,773,000	8,942,000
Cash and cash equivalents at the end of the period	\$ 25,373,000	\$ 29,056,000	\$ 14,773,000
Supplemental disclosures:			
Income taxes paid during the year	\$ 1,643,000	\$ 5,713,000	\$ 5,076,000

Net income tax refunds received during the year	\$ 2,623,000	\$ —	\$ —
Interest paid during the year	\$ 11,062,000	\$ 2,091,000	\$ 1,531,000

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

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PRIMEENERGY CORPORATION and SUBSIDIARIES  
NOTES to CONSOLIDATED FINANCIAL STATEMENTS

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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 1,580 wells and owns non-operating interests in over 817 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 full consolidation method for those partnerships which we control. The proportionate consolidation method is used to account for those undivided interests in oil and gas properties owned by the Company as well as interests held in unincorporated legal entities, such as partnerships, engaged in oil and gas production, which we do not control. For those entities which we proportionately consolidate our proportionate share of each entity’s assets, liabilities, revenue and expenses are included in the appropriate classifications in the consolidated financial statements. Reserve estimates associated with the proportionately consolidated oil and gas interests are calculated for each property at the Partnership level and depletion, depreciation and amortization (DD&A) rates are determined at the Partnership level. The Company reserve estimates are based on our ownership percentage of Partnership reserve reports. DD&A expense and evaluation of impairment may differ from the Partnership as our cost basis for the Partnership interests acquired may be different than the cost basis at the Partnership level for properties acquired by the Partnership. Inter-company balances and transactions are eliminated in preparing the consolidated financial statements. See Footnote 2 - Financial Restatement.

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.

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PRIMEENERGY CORPORATION and SUBSIDIARIES

NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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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, FAS144 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.

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.

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PRIMEENERGY CORPORATION and SUBSIDIARIES

NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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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 cost and expenses associated with the operation of the Company.

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.

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PRIMEENERGY CORPORATION and SUBSIDIARIES

NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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Recently Issued Accounting Pronouncements:

In December 2007, the FASB issued SFAS No. 160, “Noncontrolling Interest in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51.” SFAS No. 160 clarifies that a noncontrolling interest (previously commonly referred to as a minority interest) in a subsidiary is an ownership interest in the consolidated entity and should be reported as equity in the consolidated financial statements. The presentation of the consolidated income statement has been changed by SFAS No. 160, and consolidated net income attributable to both the parent and the noncontrolling interest is now required to be reported separately. Previously, net income attributable to the noncontrolling interest was typically reported as an expense or other deduction in arriving at consolidated net income and was often combined with other financial statement amounts. In addition, the ownership interests in subsidiaries held by parties other than the parent must be clearly identified, labeled, and presented in the equity in the consolidated financial statements separately from the parent’s equity. Subsequent changes in a parent’s ownership interest while the parent retains its controlling financial interest in its subsidiary should be accounted for consistently, and when a subsidiary is deconsolidated, any retained noncontrolling equity interest in the former subsidiary must be initially measured at fair value. Expanded disclosures, including a reconciliation of equity balances of the parent and noncontrolling interest are also required. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. Prospective application is required. We do not believe that the adoption of SFAS No. 160 will have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), “Business Combinations.” SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a “business” and a “business combination” have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. We cannot predict the impact that the adoption of SFAS No. 141(R) will have on our financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2007.

In May 2007, the FASB issued FSP No. FIN 48-1, “Definition of Settlement in FASB Interpretation No. 48,” which amends FIN 48 and provides guidance concerning how an entity should determine whether a tax position is “effectively,” rather than the previously required “ultimately,” settled for the purpose of recognizing previously unrecognized tax benefits. In addition, FSP No. FIN 48-1 provides guidance on determining whether a tax position has been effectively settled. The guidance in FSP No. FIN 48-1 is effective upon the initial January 1, 2007 adoption of FIN 48. Companies that have not applied this guidance must retroactively apply the provisions of this FSP to the date of the initial adoption of FIN 48. We have adopted FSP No. FIN 48-1 and no retroactive adjustments were necessary.



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PRIMEENERGY CORPORATION and SUBSIDIARIES

NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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In April 2007, the FASB issued FSP No. FIN 39-1, "Amendment of FASB Interpretation No. 39," to amend FIN 39, "Offsetting of Amounts Related to Certain Contracts." The terms "conditional contracts" and "exchange contracts" used in FIN 39 have been replaced with the more general term "derivative contracts." In addition, FSP No. FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a company's accounting policy with respect to offsetting fair value amounts. The guidance in FSP No. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. We do not believe that the adoption of FSP No. FIN 39-1 will have a material impact on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115," which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of this Statement is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of the Statement apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. The Company does not believe that SFAS No. 159 will have an impact on our financial position or results of operations.

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 United States 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. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. In November 2007, the FASB granted a one year deferral (to fiscal years beginning after November 15, 2008) for non-financial assets and liabilities to comply with SFAS No. 157. We do not believe that SFAS No. 157 will have a material impact on our financial position or results of operations.

2. Financial Restatement – The restatements reflect the change in accounting method from proportionate consolidation of partnerships that the Company controls to the full consolidation method. The Company had historically accounted for its interests in twenty limited partnerships and trusts, which own interests in oil and gas properties using the proportionate consolidation under the guidance of EITF 00-1 as related to the extractive industries. Under the guidance of EITF 04-05 the interests in limited partnerships and trusts that we control should have been fully consolidated when EITF 04-05 became effective.

The restatements also reflect the correction of gain recognition related to the sale of assets to a partnership in which the company acquired a twenty percent non-controlling interest. The Company recorded 100% of the gain however



under the guidance of EITF 01-2 the Company, since it acquired a 20% interest in the partnership, should have recorded 80% of the gain.

The effects of the restatement on reported amounts for the years ended December 31, 2007, 2006 and 2005 are presented below in the following tables:

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## RESTATED CONSOLIDATED BALANCE SHEETS

	As Reported 2007	Cumulative Effect of Prior Year Adjustments	Current Year Adjustments	Notes	As Restated 2007
<b>ASSETS:</b>					
<b>Current assets:</b>					
Cash and cash equivalents	\$ 21,313,000	\$ 4,403,000	\$ (343,000)	b	\$ 25,373,000
Restricted cash and cash equivalents	3,633,000	--	--		3,633,000
Accounts receivable, net	20,348,000	694,000	269,000	b	21,311,000
Due from related parties	212,000	(226,000)	46,000	b	32,000
Prepaid expenses	1,391,000	--	--		1,391,000
Derivative contracts	1,332,000	--	--		1,332,000
Inventory at cost	3,711,000	(3,000)	(3,000)	b	3,705,000
Deferred income tax	1,582,000	--	--		1,582,000
<b>Total current assets</b>	<b>53,522,000</b>	<b>4,868,000</b>	<b>(31,000)</b>		<b>58,359,000</b>
<b>Property and equipment, at cost:</b>					
Proved oil and gas properties at cost	368,828,000	9,139,000	941,000	a,b	378,908,000
Unproved oil and gas properties at cost	4,458,000	--	--		4,458,000
Less: Accumulated depletion and depreciation	140,115,000	5,558,000	159,000	a,b	145,514,000
	233,171,000	3,581,000	1,100,000		237,852,000
Field and office equipment	18,029,000	--	--		18,029,000
Less: Accumulated depreciation	9,820,000	--	--		9,820,000
	8,209,000	--	--		8,209,000
<b>Total net property and equipment</b>	<b>241,380,000</b>	<b>3,581,000</b>	<b>1,100,000</b>		<b>246,061,000</b>
Other assets	1,180,000	67,000	(2,000)	b	1,245,000
<b>Total assets</b>	<b>\$ 296,082,000</b>	<b>\$ 8,516,000</b>	<b>\$ 1,067,000</b>		<b>\$ 305,665,000</b>

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## RESTATED CONSOLIDATED BALANCE SHEETS

	As Reported 2007	Cumulative Effective of Prior Year Adjustment	Current Year Adjustment	Notes	As Restated 2007
<b>LIABILITIES and STOCKHOLDERS' EQUITY:</b>					
<b>Current liabilities:</b>					
Current bank debt	\$ 34,950,000	\$ --	\$ --		\$ 34,950,000
Accounts payable	26,726,000	(31,000)	85,000	b	26,780,000
Current portion of asset retirement and other long-term obligations	1,065,000	31,000	(31,000)	b	1,065,000
Derivative liability short term	4,340,000	--	--		4,340,000
Accrued liabilities	9,953,000	68,000	11,000	b	10,032,000
Due to related parties	1,563,000	(312,000)	(731,000)	b	520,000
Total current liabilities	78,597,000	(244,000)	(666,000)		77,687,000
Long-term bank debt	120,050,000	--	--		120,050,000
Asset retirement obligations	15,538,000	576,000	822,000	b	16,936,000
Derivative liability long term	3,369,000	--	--		3,369,000
Deferred income taxes	26,930,000	(1,093,000)	185,000	a,b	26,022,000
Total liabilities	244,484,000	(761,000)	341,000		244,064,000
Minority interest	1,313,000	11,220,000	396,000	b	12,929,000
<b>Stockholders' equity:</b>					
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 2007 and 2006	769,000	--	--		769,000
Paid in capital	11,024,000	--	--		11,024,000
Retained earnings	74,498,000	(1,943,000)	330,000	a	72,885,000
Accumulated other comprehensive income (loss), net	(3,618,000)	--	--		(3,618,000)
	82,673,000	(1,943,000)	330,000		81,060,000
Treasury stock, at cost 4,558,544 common shares in 2007 and 4,478,145 in 2006	(32,388,000)	--	--		(32,388,000)
Total stockholders' equity	50,285,000	(1,943,000)	330,000		48,672,000

Total liabilities and stockholders' equity	\$ 296,082,000	\$ 8,516,000	\$ 1,067,000	\$ 305,665,000
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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## RESTATED CONSOLIDATED STATEMENT of STOCKHOLDERS' EQUITY

As Reported:

	Common Stock		Additional	Retained	Accumulated	Treasury	Total
	Shares	Amount	Paid In Capital	Earnings	Other comprehensive Income		
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	\$ --	\$ (20,665,000)	\$ 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 at December 31, 2006	7,694,970	\$ 769,000	\$ 11,024,000	\$ 66,908,000	\$ 3,976,000	\$ (27,979,000)	\$ 54,698,000
Purchased 80,399 shares of common stock						(4,409,000)	(4,409,000)
Net income				7,590,000			7,590,000
Other comprehensive income (loss),					(7,594,000)		(7,594,000)

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net of taxes

Balance as of December 31, 2007	7,694,970	\$ 769,000	\$ 11,024,000	\$ 74,498,000	\$ (3,618,000)	\$ (32,388,000)	\$ 50,285,000
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Restated:

	Common Stock		Additional Paid In	Retained	Accumulated Other comprehensive	Treasury Stock	Total
	Shares	Amount	Capital	Earnings	Income		
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				23,604,000			23,604,000
Balance at December 31, 2005	7,694,970	\$ 769,000	\$ 11,024,000	\$ 46,257,000	\$ --	\$ (20,665,000)	\$ 37,385,000
Purchased 110,990 shares of common stock						(7,314,000)	(7,314,000)
Net income				18,708,000			18,708,000
Other comprehensive income, net of taxes					3,976,000		3,976,000
Balance at December 31, 2006	7,694,970	\$ 769,000	\$ 11,024,000	\$ 64,965,000	\$ 3,976,000	\$ (27,979,000)	\$ 52,755,000
Purchased 80,399 shares of common stock						(4,409,000)	(4,409,000)
Net income				7,920,000			7,920,000
Other comprehensive income (loss), net of taxes					(7,594,000)		(7,594,000)
Balance as of December 31, 2007	7,694,970	\$ 769,000	\$ 11,024,000	\$ 72,885,000	\$ (3,618,000)	\$ (32,388,000)	\$ 48,672,000



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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## CONSOLIDATED STATEMENTS OF OPERATIONS

	As Reported 2007	Current year Adjustments	Notes	As Restated 2007
<b>Revenue:</b>				
Oil and gas sales	\$ 112,708,000	\$ 9,653,000	b	\$ 122,361,000
Field service income	24,302,000	38,000	b	24,340,000
Administrative overhead fees	9,041,000	--		9,041,000
Loss on derivative instruments, net	--	--		--
Other income	404,000	--		404,000
	146,455,000	9,691,000		156,146,000
<b>Costs and expenses:</b>				
Lease operating expense	30,762,000	4,079,000	b	34,841,000
Field service expense	17,724,000	--		17,724,000
Depreciation, depletion and amortization	64,488,000	19,000	a,b	64,507,000
General and administrative expense	11,844,000	505,000	b	12,349,000
Exploration costs	633,000	--		633,000
	125,451,000	4,603,000		130,054,000
Add gain on sale and exchange of assets	598,000	--		598,000
Income from operations	21,602,000	5,088,000		26,690,000
<b>Other income and expense:</b>				
Less: Interest expense	11,062,000	--		11,062,000
Add interest income	697,000	155,000	b	852,000
Less: Minority interest	--	4,728,000	b	4,728,000
Income before provision for income taxes	11,237,000	515,000		11,752,000
Provision for income taxes	3,647,000	185,000	a	3,832,000
Net income	\$ 7,590,000	\$ 330,000		\$ 7,920,000
Basic net income per common share	\$ 2.39	\$ 0.11		\$ 2.50
Diluted net income per common share	\$ 1.93	\$ 0.09		\$ 2.02



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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## CONSOLIDATED STATEMENTS of CASH FLOWS

for the year ended December 31, 2007

	As Reported 2007	Current Year Adjustments	Notes	As Restated 2007
Cash flows from operating activities:				
Net income	\$ 7,590,000	\$ 330,000	a	\$ 7,920,000
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion on discounted liabilities	64,488,000	19,000	a,b	64,507,000
Dry hole and abandonment costs	343,000	--		343,000
Gain on sale of properties	(598,000)	--		(598,000)
Non-cash incentive compensation expense	--	--		--
Provision for deferred income taxes	1,030,000	185,000	a	1,215,000
Minority interest in earnings of partnerships	--	4,728,000	b	4,728,000
Changes in assets and liabilities:				
(Increase) decrease in accounts receivable	13,168,000	1,108,000	b	14,276,000
(Increase) decrease in due from related parties	443,000	863,000	b	1,306,000
(Increase) decrease in inventories	331,000	(6,000)	b	325,000
(Increase) decrease in prepaid expenses and other assets	(175,000)	--		(175,000)
Increase (decrease) in accounts payable	325,000	(199,000)	b	126,000
Increase (decrease) in accrued liabilities	132,000	(79,000)	b	53,000
Increase (decrease) in due to related parties	1,088,000	--		1,088,000
Net cash provided by operating activities	88,165,000	6,949,000		95,114,000
Cash flows from investing activities				
Capital expenditures, including exploration expense	(106,601,000)	(3,218,000)	b	(109,819,000)
Proceeds from sale of properties and equipment	598,000	--		598,000
Net cash used in investing activities	(106,003,000)	(3,218,000)		(109,221,000)
Cash flows from financing activities				
Purchase of stock for treasury	(4,409,000)	--		(4,409,000)
Increase in long-term bank debt and other long-term obligations	105,867,000	--		105,867,000
Repayment of long-term bank debt and other long-term obligations	(86,960,000)	--		(86,960,000)
Distribution to minority interest	--	(4,074,000)	b	(4,074,000)
Net cash provided by (used in) financing activities	14,498,000	(4,074,000)		10,424,000

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Net increase(decrease) in cash and cash equivalents	(3,340,000)	(343,000)		(3,683,000)
Cash and cash equivalents at the beginning of the period	24,653,000	4,403,000	b	29,056,000
Cash and cash equivalents at the end of the period	\$ 21,313,000	\$ 4,060,000		\$ 25,373,000

Supplemental disclosures:

Income taxes paid during the year	\$ 1,643,000	\$ --		\$ 1,643,000
Net income tax refunds received during the year	\$ 2,623,000	\$ --		\$ 2,623,000
Interest paid during the year	\$ 11,062,000	\$ --		\$ 11,062,000

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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 CONSOLIDATED BALANCE SHEETS

	As Reported 2006	Cumulative Effect of Prior Year Adjustments	Current Year Adjustments	Notes	As Restated 2006
<b>ASSETS:</b>					
Current assets:					
Cash and cash equivalents	\$ 24,653,000	\$ 3,654,000	\$ 749,000	b	\$ 29,056,000
Restricted cash and cash Equivalents	2,528,000	--	--		2,528,000
Accounts receivable, net	32,970,000	1,117,000	(423,000)	b	33,664,000
Due from related parties	655,000	(255,000)	(29,000)	b	429,000
Prepaid expenses	1,269,000	--	--		1,269,000
Derivative contracts	6,085,000	--	--		6,085,000
Inventory at cost	3,521,000	(6,000)	3,000	b	3,518,000
Deferred income tax	--	--	--		--
Total current assets	71,681,000	4,510,000	358,000		76,549,000
Property and equipment, at cost:					
Proved oil and gas properties at cost	284,698,000	9,564,000	(425,000)	a,b	293,837,000
Unproved oil and gas properties at cost	5,047,000	--	--		5,047,000
Less: Accumulated depletion and depreciation	78,005,000	(6,190,000)	632,000	a,b	(83,563,000)
	211,740,000	3,374,000	207,000		215,321,000
Field and office equipment	15,793,000	--	--		15,793,000
Less: Accumulated depreciation	8,351,000	--	--		8,351,000
	7,442,000	--	--		7,442,000
Total net property and equipment	219,182,000	3,374,000	207,000		222,763,000
Other assets	729,000	69,000	(2,000)	b	796,000
Total assets	\$ 291,592,000	\$ 7,953,000	\$ 563,000		\$ 300,108,000

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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 CONSOLIDATED BALANCE SHEETS

	As Reported 2006	Cumulative Effective of Prior Year Adjustment	Current Year Adjustment	Notes	As Restated 2006
<b>LIABILITIES and STOCKHOLDERS' EQUITY:</b>					
<b>Current liabilities:</b>					
Current bank debt	\$ --	\$ --	\$ --		\$ --
Accounts payable	42,658,000	(2,000)	(29,000)	b	42,627,000
Current portion of asset retirement and other long-term obligations	314,000	102,000	(71,000)	b	345,000
Derivative liability short term	1,961,000	--	--		1,961,000
Accrued liabilities	22,030,000	168,000	(100,000)	b	22,098,000
Due to related parties	477,000	(779,000)	467,000	b	165,000
<b>Total current liabilities</b>	<b>67,440,000</b>	<b>(511,000)</b>	<b>267,000</b>		<b>67,196,000</b>
Long-term bank debt	136,460,000	--	--		136,460,000
Asset retirement obligations	6,314,000	464,000	112,000	b	6,890,000
Derivative liability long term	--	--	--		--
Deferred income taxes	25,367,000	(1,323,000)	230,000	a,b	24,274,000
<b>Total liabilities</b>	<b>235,581,000</b>	<b>(1,370,000)</b>	<b>609,000</b>		<b>234,820,000</b>
Minority interest	1,313,000	11,674,000	(454,000)	b	12,533,000
<b>Stockholders' equity:</b>					
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 2007 and 2006	769,000	--	--		769,000
Paid in capital	11,024,000	--	--		11,024,000
Retained earnings	66,908,000	(2,351,000)	408,000	a	64,965,000
Accumulated other comprehensive income (loss), net	3,976,000	--	--		3,976,000
	82,677,000	(2,351,000)	408,000		80,734,000
Treasury stock, at cost 4,558,544 common shares in 2007 and 4,478,145 in 2006	(27,979,000)	--	--		(27,979,000)
<b>Total stockholders' equity</b>	<b>54,698,000</b>	<b>(2,351,000)</b>	<b>408,000</b>		<b>52,755,000</b>

Total liabilities and stockholders' equity	\$ 291,592,000	\$ 7,953,000	\$ 563,000	\$ 300,108,000
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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## CONSOLIDATED STATEMENTS OF OPERATIONS

	As Reported 2006	Current year Adjustments	Notes	As Restated 2006
<b>Revenue:</b>				
Oil and gas sales	\$ 61,924,000	\$ 9,726,000	b	\$ 71,650,000
Field service income	20,319,000	38,000	b	20,357,000
Administrative overhead fees	9,704,000	--		9,704,000
Loss on derivative instruments, net	--	--		--
Other income	112,000	--		112,000
	92,059,000	9,764,000		101,823,000
<b>Costs and expenses:</b>				
Lease operating expense	21,040,000	4,297,000	b	25,337,000
Field service expense	15,796,000	6,000	b	15,802,000
Depreciation, depletion and amortization	14,437,000	(67,000)	a,b	14,370,000
General and administrative expense	12,400,000	577,000	b	12,977,000
Exploration costs	1,162,000	--		1,162,000
	64,835,000	4,813,000		69,648,000
Add gain on sale and exchange of assets	3,017,000	712,000		3,729,000
Income from operations	30,241,000	5,663,000		35,904,000
<b>Other income and expense:</b>				
Less: Interest expense	2,091,000	--		2,091,000
Add interest income	360,000	148,000	b	508,000
Less: Minority interest	--	5,173,000	b	5,173,000
Income before provision for income taxes	28,510,000	638,000		29,148,000
Provision for income taxes	10,210,000	230,000	a	10,440,000
Net income	\$ 18,300,000	\$ 408,000		\$ 18,708,000
Basic net income per common share	\$ 5.52	\$ 0.13		\$ 5.65
Diluted net income per common share	\$ 4.50	\$ 0.10		\$ 4.60

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## CONSOLIDATED STATEMENTS of CASH FLOWS

for the year ended December 31, 2006

	As Reported 2006	Current Year Adjustments	Notes	As Restated 2006
<b>Cash flows from operating activities:</b>				
Net income	\$ 18,300,000	\$ 408,000	a	\$ 18,708,000
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion on discounted liabilities	14,437,000	(67,000)	a,b	14,370,000
Dry hole and abandonment costs	510,000	--		510,000
Gain on sale of properties	(3,017,000)	(712,000)	b	(3,729,000)
Non-cash incentive compensation expense	1,313,000	--		1,313,000
Provision for deferred income taxes	11,557,000	230,000	a	11,787,000
Minority interest in earnings of partnerships	--	5,173,000	b	5,173,000
Changes in assets and liabilities:				
(Increase) decrease in accounts receivable	(16,411,000)	931,000	b	(15,480,000)
(Increase) decrease in due from related parties	330,000	154,000	b	484,000
(Increase) decrease in inventories	(3,133,000)	(3,000)	b	(3,136,000)
(Increase) decrease in prepaid expenses and other assets	6,382,000	67,000	b	6,449,000
Increase (decrease) in accounts payable	3,716,000	(206,000)	b	3,510,000
Increase (decrease) in accrued liabilities	(1,450,000)	(68,000)	b	(1,518,000)
Increase (decrease) in due to related parties	(552,000)	(68,000)	b	(620,000)
Net cash provided by operating activities	31,982,000	5,839,000		37,821,000
<b>Cash flows from investing activities</b>				
Capital expenditures, including exploration expense	(121,345,000)	(1,359,000)	b	(122,704,000)
Proceeds from sale of properties and equipment	3,017,000	712,000	b	3,729,000
Net cash used in investing activities	(118,328,000)	(647,000)		(118,975,000)
<b>Cash flows from financing activities</b>				
Purchase of stock for treasury	(7,314,000)	--		(7,314,000)
Increase in long-term bank debt and other long-term obligations	198,362,000	--		198,362,000
Repayment of long-term bank debt and other long-term obligations	(91,168,000)	--		(91,168,000)
Distribution to minority interest		(4,443,000)	b	(4,443,000)
Net cash provided by (used in) financing activities	99,880,000	(4,443,000)		95,437,000

Net increase in cash and cash equivalents	13,534,000	749,000	14,283,000
Cash and cash equivalents at the beginning of the period	11,119,000	3,654,000	b 14,773,000
Cash and cash equivalents at the end of the period	\$ 24,653,000	\$ 4,403,000	\$ 29,056,000
Supplemental disclosures:			
Income taxes paid during the year	\$ 5,713,000	\$ --	\$ 5,713,000
Interest paid during the year	\$ 2,091,000	\$ --	\$ 2,091,000

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## CONSOLIDATED STATEMENTS OF OPERATIONS

	As Reported 2005	Current year adjustments	Notes	As Restated 2005
<b>Revenue:</b>				
Oil and gas sales	\$ 53,988,000	\$ 11,332,000	b	\$ 65,320,000
Field service income	15,182,000	44,000	b	15,226,000
Administrative overhead fees	7,068,000	--		7,068,000
Loss on derivative instruments, net	(415,000)	--		(415,000)
Other income	25,000	--		25,000
	75,848,000	11,376,000		87,224,000
<b>Costs and expenses:</b>				
Lease operating expense	18,573,000	4,668,000	b	23,241,000
Field service expense	12,791,000	13,000	b	12,804,000
Depreciation, depletion and amortization	11,274,000	510,000	a,b	11,784,000
General and administrative expense	10,493,000	555,000	b	11,048,000
Exploration costs	664,000	--		664,000
	53,795,000	5,746,000		59,541,000
Add gain on sale and exchange of assets	20,334,000	(3,746,000)	a	16,588,000
Income from operations	42,387,000	1,884,000		44,271,000
<b>Other income and expense:</b>				
Less interest expense	1,531,000	--		1,531,000
Add interest income	98,000	55,000	b	153,000
Less minority interest	--	5,613,000	b	5,613,000
Income before provision for income taxes	40,954,000	(3,674,000)		37,280,000
Provision for income taxes	14,999,000	(1,323,000)	a	13,676,000
Net income	\$ 25,955,000	\$ (2,351,000)		\$ 23,604,000
Basic net income per common share	\$ 7.64	\$ (0.69)		\$ 6.95
Diluted net income per common share	\$ 6.27	\$ (0.57)		\$ 5.70

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## RESTATED CONSOLIDATED STATEMENTS of CASH FLOWS

for the year ended December 31, 2005

	As Reported 2005	Current Year Adjustments	Notes	As Restated 2005
Cash flows from operating activities:				
Net income	\$ 25,955,000	\$ (2,351,000)	a	\$ 23,604,000
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion, amortization and accretion on discounted liabilities	11,274,000	510,000	a,b	11,784,000
Dry hole and abandonment costs	262,000	--		262,000
Gain on sale of properties	(20,334,000)	3,746,000	b	(16,588,000)
Provision for deferred income taxes	6,230,000	(1,323,000)	a	4,907,000
Minority interest in earnings of partnerships	--	5,613,000	b	5,613,000
Changes in assets and liabilities:				
(Increase) decrease in accounts receivable	(7,803,000)	1,397,000	b	(6,406,000)
(Increase) decrease in due from related parties	(985,000)	778,000	b	(207,000)
(Increase) decrease in inventories	--	(6,000)	b	(6,000)
(Increase) decrease in prepaid expenses and other assets	(7,320,000)	69,000	b	(7,251,000)
Increase (decrease) in accounts payable	5,510,000	(278,000)	b	5,232,000
Increase (decrease) in accrued liabilities	5,385,000	(168,000)	b	5,217,000
Increase (decrease) in due to related parties	431,000	--		431,000
Net cash provided by operating activities	18,605,000	7,987,000		26,592,000
Cash flows from investing activities				
Capital expenditures, including exploration expense	(54,440,000)	403,000	b	(54,037,000)
Proceeds from sale of properties and equipment	46,796,000	(3,746,000)	b	43,050,000
Net cash used in investing activities	(7,644,000)	(3,343,000)		(10,987,000)
Cash flows from financing activities				
Purchase of stock for treasury	(4,456,000)	--		(4,456,000)
Increase in long-term bank debt and other long-term obligations	65,570,000	--		65,570,000
Repayment of long-term bank debt and other long-term obligations	(67,432,000)	--		(67,432,000)
Distribution to minority interest		(3,456,000)	b	(3,456,000)
Net cash provided by (used in) financing activities	(6,318,000)	(3,456,000)		(9,774,000)
Net increase in cash and cash equivalents	4,643,000	1,188,000		5,831,000

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Cash and cash equivalents at the beginning of the period	6,476,000	2,466,000	b	8,942,000
Cash and cash equivalents at the end of the period	\$ 11,119,000	\$ 3,654,000		\$ 14,773,000

Supplemental disclosures:

Income taxes paid during the year	\$ 5,076,000	\$ --		\$ 5,076,000
Interest paid during the year	\$ 1,531,000	\$ --		\$ 1,531,000

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PRIMEENERGY CORPORATION and SUBSIDIARIES

NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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Explanatory Notes to Restated Consolidated Statements of Operations, Balance Sheets and Statements of Cash Flows

- a) The correction of the recorded gain on sale of assets to a partnership in which the Company acquired a twenty percent non-controlling interest in the year ended December 31, 2005 resulted in a decrease of \$3.7 million in gain on sale and a decrease in depletion and depreciation of \$72,000 for the year ended December 31, 2005, and a corresponding decrease in proved oil and gas properties and accumulated depletion and depreciation as of December 31, 2005. This change in the basis of oil and gas properties resulted in a reduction of depletion and depreciation expense of \$638,000 and \$515,000 in 2006 and 2007 respectively and corresponding reductions in accumulated depletion and depreciation. The change in gain and depletion and depreciation expense resulted in the noted change in deferred taxes for each period.
- b) The restatement of these items, net of amounts described in note a, results from the change from the proportionate consolidation method to the full consolidation method of accounting for the limited partnerships and trusts that we control.

3. 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 \$371,000 in 2007, \$526,000 in 2006.

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.

To record this transaction, the Company applied the guidance of EITF 86-29, Non monetary transactions: Magnitude of Boot and the Exceptions to the Use of Fair Value. In this transaction, the boot was significant (in excess of 25% of the fair value of the exchange), therefore, the transaction was treated as a monetary transaction with the assets recorded at fair value. The Company recorded proceeds of \$61.2 million consisting of cash of \$43.2 million and the

fair market value of the General Partner interest of \$18.0 million. The fair market value of the General Partner interest was determined by calculating 20% of the total agreed value of all properties acquired by the Partners. The related properties had a book value of \$42.5 million resulting in a total gain of \$18.7 million, however in accordance with EITF 01-2, since the Company acquired a 20% interest in Partners the Company recognized a gain of \$15 million, representing 80% of the total gain. The Company uses the proportionate consolidation method of accounting for its interest in Partners under the Guidance of EITF 00-1 as related to the extractive industries since the Company does not control Partners.

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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.

## 4. Additional Balance Sheet Information (restated)

Accounts receivable at December 31, 2007 and 2006, consisted of the following:

	December 31,	
	2007	2006
Joint interest billing	\$ 3,192,000	\$ 13,054,000
Trade receivables	2,352,000	2,367,000
Oil and gas sales	14,785,000	9,458,000
Income tax receivable	795,000	3,023,000
Other	415,000	5,912,000
	21,539,000	33,814,000
Less: allowance for doubtful accounts	(228,000)	(150,000)
Total	\$ 21,311,000	\$ 33,664,000

Accounts Payable at December 31, 2007 and 2006, consisted of the following:

	December 31,	
	2007	2006
Trade	\$ 12,364,000	\$ 34,324,000
Royalty and other owners	11,209,000	6,232,000
Other	3,207,000	2,071,000
Total	\$ 26,780,000	\$ 42,627,000

Accrued Liabilities at December 31, 2007 and 2006, consisted of the following:

	December 31,	
	2007	2006
Compensation and related expenses	\$ 1,687,000	\$ 1,584,000
Property costs	4,551,000	16,256,000
Income tax	--	270,000
Other	3,794,000	3,988,000
	\$ 10,032,000	\$ 22,098,000

## 5. Property and Equipment

Total interest costs incurred during 2007 was \$12,984,000. Of this amount, the Company capitalized \$1,922,000. 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.

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## 6. 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, 2007, the borrowing bases and outstanding balances were \$89 million under the onshore credit facility at a weighted average interest rate of 7.78%, and \$66 million under the offshore credit facility at a weighted average interest rate of 9.79%. Currently, the borrowing base and outstanding balance under the onshore credit facility is \$96 million and \$80.6 million, respectively, and the borrowing base and outstanding balance under the offshore credit facility is \$57.4 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.

## 7. 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
2008	\$ 605,000
2009	350,000
2010	71,000



2011	5,000
Thereafter	--
Total minimum payments	\$ 1,031,000

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## Asset Retirement Obligation:

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2007 and 2006 is as follows:

	2007 Restated	2006 Restated
Asset retirement obligation - beginning of period	\$ 7,047,000	\$ 3,160,000
Liabilities incurred	468,000	3,033,000
Liabilities settled	(367,000)	(348,000)
Accretion expense	461,000	149,000
Revisions in estimated liabilities	9,752,000	1,053,000
Asset retirement obligation - end of period	\$ 17,361,000	\$ 7,047,000

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.

## 8. 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, 2007, 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.

## 9. 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, 2007 and 2006, options on 767,500 shares were outstanding and exercisable at prices ranging from \$1.00 to \$1.25.

In January 2006, Prime Offshore L.L.C. (the LLC), a subsidiary of the Registrant, entered into a Grant of Shares Agreement with two key employees of the LLC. The grant of these shares constituted a reevaluation event under the Limited Liability Company Agreement. The Grant Agreement set forth the carrying value of the assets of the LLC, representing the agreed to estimate of the fair market value of the properties and other assets and liabilities of the LLC, as of the date of the agreement. Each employee was granted 430,280 shares of the LLC having a fair market value of \$1.53 per share. There are no requisite service periods or vesting periods relating to the grants, therefore, the aggregate compensation cost of \$1,313,000 was charged to expense in the Consolidated Statement of Operations and reported as an adjustment to net cash provided by operating activities on the Consolidated Statement of Cash Flows.

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## 10. Income Taxes (restated)

The components of the provision for income taxes for the years ended December 31, 2007, 2006 and 2005 are as follows:

	2007	2006	2005
Federal:			
Current	\$ 567,000	\$ (1,814,000)	\$ 8,011,000
Deferred	2,662,000	11,638,000	4,106,000
State:			
Current	660,000	467,000	803,000
Deferred	(57,000)	149,000	756,000
Total	\$ 3,832,000	\$ 10,440,000	\$ 13,676,000

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

	December 31, 2007	December 31, 2006
Current assets:		
Compensation allowance	\$ 443,000	\$ 252,000
Allowance for doubtful accounts	56,000	56,000
Unrealized loss on hedging transactions	1,083,000	-
Total current deferred income tax assets	\$ 1,582,000	\$ 308,000
Current liabilities:		
Unrealized gain on hedging transactions	\$ --	\$ 2,270,000
Net current deferred tax liability (asset)	\$ (1,582,000)	\$ 1,962,000
Noncurrent assets:		
Alternative minimum tax credits	\$ 7,478,000	\$ 7,328,000
Net operating loss carryforwards	2,526,000	903,000
Percentage depletion carryforwards	1,099,000	351,000
Unrealized gain on hedging transactions	953,000	--
Total noncurrent assets	\$ 12,056,000	\$ 8,582,000

Noncurrent liabilities:		
Basis differences relating to partnerships	\$ 1,381,000	\$ 1,213,000
Depletion and depreciation	36,697,000	31,547,000
Unrealized gain on hedging transactions	--	96,000
Total noncurrent liabilities	\$ 38,078,000	\$ 32,856,000
Net noncurrent deferred income tax liabilities	\$ 26,022,000	\$ 24,274,000

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

The total provision for income taxes for the years ended December 31, 2007, 2006 and 2005 varies from the federal statutory tax rate as a result of the following:

	December 31, 2007	December 31, 2006	December 31, 2005
Expected tax expense	\$ 4,006,000	\$ 9,923,000	\$ 12,690,000
State income tax, net of federal benefit	398,000	411,000	1,029,000
Percentage depletion	(697,000)	(352,000)	(429,000)
Executive Compensation	125,000	542,000	467,000
Other, Net	--	(84,000)	(81,000)
Tax expense	\$ 3,832,000	\$ 10,440,000	\$ 13,676,000

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 2007 for regular tax purposes, which will be carried forward. As intangible drilling costs are a preference item for the alternative minimum tax (AMT), the Company will have a Federal Tax Liability based on the AMT. The current deductibility of intangible drilling costs is the primary reason for both the low current federal tax expense and the increase in deferred tax liability.

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.

#### 11. Segment Information and Major Customers (restated)

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 2007.

Oil Purchasers:		Gas Purchasers:	
Texon Distributing L.P.	30%	Unimark LLC	12%
Plains All American Inc.	54%	Cokin os Energy Corporation	57%

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.

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PRIMEENERGY CORPORATION and SUBSIDIARIES

NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

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12. 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, 2007, the Company had twelve cash flow hedges open: two natural gas price swap arrangements and ten crude oil collar arrangements. At December 31, 2007, \$5.65 million (\$3.62 million net of tax) unrealized loss was recorded in Accumulated Other Comprehensive Income, along with a \$1.32 million and \$723 thousand short-term and long-term derivative receivable and a \$4.34 million and \$3.69 million short-term and long-term derivative payable. 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, 2007, natural gas price swaps cover 4,635 Mmcf of production at a weighted average price of \$8.23 for 2008 and \$9.75 for 2009. The oil price collar covers 907 Mbbl of production at a floor price ranging from \$60.00 to \$65.00, a ceiling price ranging from \$77.40 to \$86.50 and a third-tier call of \$100 on one collar arrangement.

Assuming no change in commodity prices, after December 31, 2007, the Company would expect to reclassify to the Statement of Operations, over the next 12 months, \$1.92 million in after-tax loss associated with commodity hedges. This reclassification represents the net short-term receivable and payables associated with open positions currently not reflected in earnings at December 31, 2007 related to anticipated 2008 production.

13. Related Party Transactions (restated)

The Company, as managing general partner or managing trustee, makes an annual offer to repurchase the interests of the partners and trust unit holders in certain of the Partnerships or Trusts. The Company purchased such interests in an amount totaling \$371,000 during 2007 and \$526,000 during 2006.

Treasury stock purchases in 2007 and 2006 included shares acquired from related parties. Purchases from related parties included a total of 31,700 shares purchased for a total consideration of \$1,743,500 in 2007 and 40,759 shares purchased for a total consideration of \$2,623,564 in 2006.

Receivables from related parties consist of reimbursable general and administrative costs, lease operating expenses and reimbursement for property development and related costs. These receivables are due from joint venture partners, which may include members of the Company's Board of Directors.

Payables owed to related parties primarily represents receipts collected by the Company as agent, for the joint venture partners, which may include members of the Company's Board of Directors, for oil and gas sales net of expenses.

14. Restricted Cash and Cash Equivalents



Restricted cash and cash equivalents includes \$3,633,000 and \$2,528,000 at December 31, 2007 and 2006, respectively, of cash primarily pertaining to oil and gas revenue payments. There were corresponding accounts payable recorded at December 31, 2007 and 2006 for these liabilities.

15. 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 \$437,000 and \$366,000 in 2007 and 2006, respectively.

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## NOTES to CONSOLIDATED FINANCIAL STATEMENTS, Continued

## 16. Earnings per Share (restated)

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, 2007		
	Net Income	Number of Shares	Per share Amount
Net income per common share	\$ 7,920,000	3,174,032	\$ 2.50
Effect of dilutive securities:			
Options	--	752,868	
Diluted net income per common share	\$ 7,920,000	3,926,900	\$ 2.02

	Year ended December 31, 2006		
	Net Income	Number of Shares	Per share Amount
Net income per common share	\$ 18,708,000	3,314,003	\$ 5.65
Effect of dilutive securities:			
Options	--	755,682	
Diluted net income per common share	\$ 18,708,000	4,069,685	\$ 4.60

	Year ended December 31, 2005		
	Net Income	Number of Shares	Per share Amount
Net income per common share	\$ 23,604,000	3,397,820	\$ 6.95
Effect of dilutive securities:			
Options		742,589	
Diluted net income per common share	\$ 23,604,000	4,140,409	\$ 5.70

## 17. Selected Quarterly Financial Information (Restated and Unaudited)

	2007	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Revenue	\$ 42,856,000	\$ 44,278,000	\$ 38,519,000	\$ 30,493,000	
Operating income	5,556,000	5,654,000	8,067,000	7,413,000	
Net income	955,000	854,000	2,794,000	3,317,000	

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Net income per common share \$	0.32 \$	0.27 \$	0.88 \$	1.03
Diluted net income per common share \$	0.25 \$	0.22 \$	0.71 \$	0.84

2006	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Revenue \$	22,768,000 \$	27,543,000 \$	26,023,000 \$	25,489,000
Operating income	5,665,000	13,119,000	8,717,000	8,403,000
Net income	2,494,000	6,712,000	5,421,000	4,081,000
Net income per common share \$	0.71 \$	2.06 \$	1.65 \$	1.23
Diluted net income per common share \$	0.59 \$	1.67 \$	1.34 \$	1.00

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PRIMEENERGY CORPORATION and SUBSIDIARIES

SUPPLEMENTARY INFORMATION

PRIMEENERGY CORPORATION and SUBSIDIARIES

CAPITALIZED COSTS RELATING to OIL and GAS PRODUCING ACTIVITIES

December 31, 2007, 2006 and 2005

(Unaudited)

	2007	2006	2005
Developed oil and gas properties	\$ 378,908,000	\$ 293,837,000	\$ 134,812,000
Undeveloped oil and gas properties	4,458,000	5,047,000	6,166,000
	383,366,000	298,884,000	140,978,000
Accumulated depreciation, depletion and valuation allowance	145,514,000	83,563,000	71,424,000
Net capitalized costs	\$ 237,852,000	\$ 215,321,000	\$ 69,554,000

COSTS INCURRED in OIL and GAS PROPERTY ACQUISITION,

EXPLORATION and DEVELOPMENT ACTIVITIES

Years ended December 31, 2007, 2006 and 2005

(Unaudited)

	2007	2006	2005
Acquisition of Properties			
Developed	\$ 371,000	\$ 1,408,000	\$ 1,569,000
Undeveloped	\$ 184,000	\$ 5,047,000	\$ 6,166,000
Exploration Costs	\$ 633,000	\$ 17,429,000	\$ 664,000
Development Costs	\$ 86,574,000	\$ 136,968,000	\$ 45,622,000

See accompanying notes to supplementary information.

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PRIMEENERGY CORPORATION and SUBSIDIARIES

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

Years Ended December 31, 2007, 2006 and 2005

(Unaudited)

	2007	2006	2005
Future cash inflows	\$ 996,419,000	\$ 747,812,000	\$ 776,004,000
Future production and development costs	(487,001,000)	(324,750,000)	(328,619,000)
Future income tax expenses	(127,961,000)	(103,889,000)	(139,363,000)
Future net cash flows	381,457,000	319,163,000	308,022,000
10% annual discount for estimated timing of cash flow	(155,997,000)	(102,975,000)	(134,533,000)
Standardized measure of discounted future net cash flows	\$ 225,460,000	\$ 216,188,000	\$ 173,489,000

See accompanying notes to supplementary information.

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## 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, 2007, 2006 and 2005

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2007, 2006 and 2005:

For Year Ended December 31,	2007	2006	2005
Sales of oil and gas produced, net of production costs	\$ (83,990,000)	\$ (43,941,000)	\$ (37,527,000)
Net changes in prices and production costs	93,088,000	(58,710,000)	70,033,000
Extensions, discoveries and improved recovery	10,554,000	147,292,000	64,175,000
Revisions of previous quantity estimates	(16,462,000)	(2,717,000)	33,492,000
Reserves purchased, net of development costs	(23,000)	(386,000)	(95,000)
Net change in development costs	(27,304,000)	1,870,000	7,914,000
Reserves sold	--	--	(64,246,000)
Accretion of discount	32,564,000	12,284,000	8,020,000
Net change in income taxes	(1,979,000)	(7,862,000)	(28,441,000)
Changes in production rates (timing) and other	973,000	(5,131,000)	8,101,000
Net change	7,421,000	42,699,000	61,426,000
Standardized measure of discounted future net cash flow:			
Beginning of year	216,188,000	173,489,000	112,063,000
End of year	\$ 223,609,000	\$ 216,188,000	\$ 173,489,000

See accompanying notes to supplementary information.

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## RESERVE QUANTITY INFORMATION

Years Ended December 31, 2007, 2006 and 2005

(Unaudited)

	2007		2006		2005	
	Oil (bbls.)	Gas (Mcf)	Oil (bbls.)	Gas (Mcf)	Oil (bbls.)	Gas (Mcf)
Proved developed and undeveloped reserves:						
Beginning of year	5,205,000	77,912,000	4,711,000	55,340,000	2,981,000	56,607,000
Extensions, discoveries and improved recovery	941,000	2,343,000	812,000	31,394,000	807,000	11,087,000
Revisions of previous estimates	1,007,000	(7,531,000)	138,000	(2,410,000)	456,000	5,989,000
Purchases	--	--	--	--	--	--
Reserves sold	--	--	--	--	(89,000)	(12,701,000)
Production	(561,000)	(11,132,000)	(456,000)	(6,411,000)	(443,000)	(5,641,000)
End of year	6,592,000	61,412,000	5,205,000	77,913,000	4,712,000	55,341,000
Proved developed reserves	5,640,000	58,814,000	4,986,000	75,434,000	4,529,000	54,373,000

See accompanying notes to supplementary information.

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## PRIMEENERGY CORPORATION and SUBSIDIARIES

## RESULTS of OPERATIONS from OIL and GAS PRODUCING ACTIVITIES

Years Ended December 31, 2007, 2006 and 2005

(Unaudited)

	2007	2006	2005
Revenue:			
Oil and gas sales	\$ 122,361,000	\$ 71,650,000	\$ 65,320,000
Costs and expenses:			
Lease operating expense	34,841,000	25,337,000	23,241,000
Exploration costs	633,000	1,162,000	664,000
Depreciation and Depletion	59,792,000	12,704,000	10,635,000
Income tax expense	7,569,000	9,422,000	8,281,000
	102,835,000	48,625,000	42,821,000
Results of operations from producing activities (excluding corporate overhead and interest costs)	\$ 19,526,000	\$ 23,025,000	\$ 22,499,000

See accompanying notes to supplementary information.



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PRIMEENERGY CORPORATION and SUBSIDIARIES

NOTES to SUPPLEMENTARY INFORMATION

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(Unaudited)

1. Presentation of Reserve Disclosure Information

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

2. Determination of Proved Reserves

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

3. Results of Operations from Oil and Gas Producing Activities

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

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

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

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

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

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

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



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5. Changes in Reserves

The 2007 extensions and discoveries reflect the successful drilling activity related to our West Texas properties. The downward revisions during 2007 are related to our offshore properties.

The 2006 extensions and discoveries included 31.4 BCF of natural gas primarily related to additions from the Company's offshore drilling activities and 812,000 barrels of oil primarily related to the Company's drilling activity in West Texas. The Company spent \$17 million and \$137 million on exploration and development activities, respectively, during 2006.

The 2005 extensions and discoveries included 11 BCF of natural gas primarily related to additions from the Company's offshore drilling activities and 807,000 barrels of oil primarily related to the Company's drilling activity in West Texas. The Company spent \$664,000 and \$44 million on exploration and development activities, respectively, during 2005.

The 2005 upward revision of previous estimates was caused by the increase in oil and gas prices at the end of 2005. The 2005 sales of reserves is primarily related to the sale of reserves in the Partners transaction, discussed more fully in footnote 2 – Significant Acquisitions and Dispositions.