PrimeEnergy

PrimeEnergy Corporation

ANNUAL REPORT
2009

President's Letter

PrimeEnergy is disappointed to report a loss of $23,000,000 for the year 2009. The loss was primarily attributed to the large depreciation, depletion and amortization rate on our offshore properties. The Company also suffered dramatically lower product pricing both for natural gas and crude oil which significantly lowered our revenues.

Our discretionary cash flow for 2009 was in excess of $34,000,000 and we believe that in 2010 we should exceed this number. The cash flow in 2009 was used to reduce debt by $10,000,000 and drill 13 wells, all of which were successful. The Company also retired 11,082 shares of stock. Since 1990, we have retired 4,664,098 shares of stock at an average price of $8.04. This represents approximately 61% of the original outstanding common stock. The Company also retired 769,500 options at a cost of $607,000.

We are proud of the continued growth of our oilfield operations. Our district offices in Midland and Houston, Texas, Oklahoma City, Oklahoma and Charleston, West Virginia continue to provide quality operations for 1,600 wells and over 1,000 working interest partners.

We are also proud of the growth of our three wholly-owned well servicing subsidiaries, Eastern Oil Well Service, Southwest Oilfield Construction Company and EOWS Midland Company. During 2009 our equipment companies generated cash flow of $2,013,000. We continue to invest a limited amount of capital in these businesses by acquiring additional equipment and refurbishing our existing equipment.

The Company's strategy in 2010 is to continue to reduce its outstanding debt. We are planning on drilling in excess of 20 wells, mainly in the Permian Basin, which are all Proved Undeveloped Locations. We will continue to use part of our cash flow to retire outstanding stock. The ongoing decrease of our leveraged position over the years will better provide the Company the ability to participate in a significant acquisition, should the opportunity arise.

The Annual Meeting of Shareholders will be held at One Landmark Square, Stamford, Connecticut at our corporate office. The meeting will be held on May 20, 2010 at 9:00 a.m. (EDT). I encourage you to attend and meet our Board of Directors and management and allow us to answer any questions you may have.

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

Sincerely,

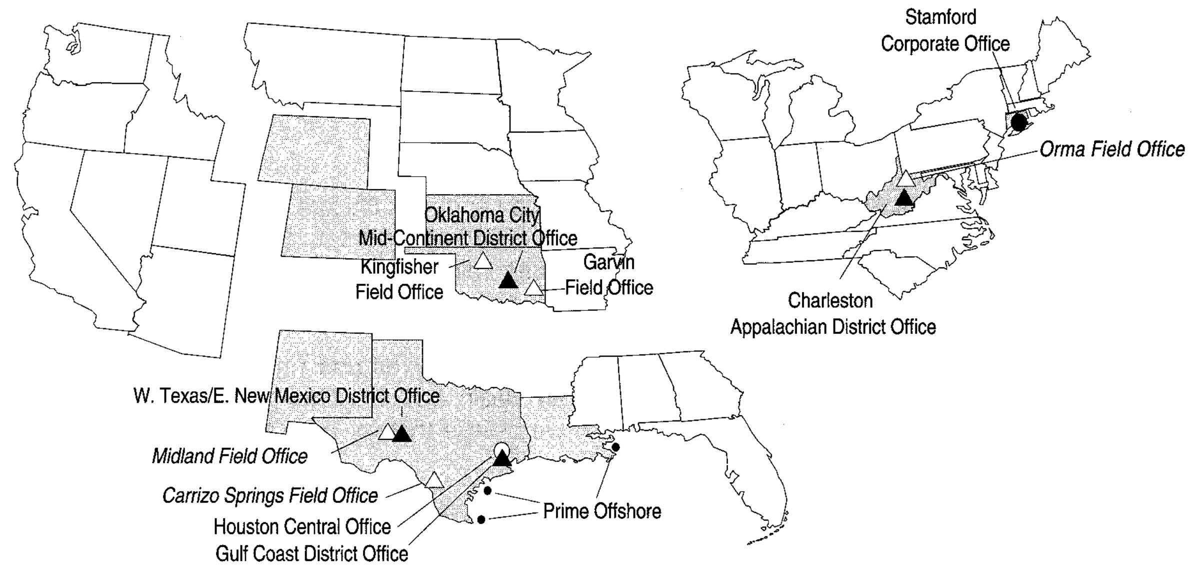
Charles E. Drimal, Jr.
President, CEO

The Company

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

The Company is headquartered in Stamford, Connecticut, with operating offices in Houston and Midland, Texas, Oklahoma City, Oklahoma, and Charleston, West Virginia. PrimeEnergy owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the continental United States and in the Gulf of Mexico. The Company operates 1,600 wells and owns non-operating interests in approximately 800 additional wells. The Company's off-shore operations in the Gulf of Mexico are conducted through its subsidiary, Prime Offshore L.L.C., with its offices in Houston, Texas.

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



The Company's Annual Report, Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission is reproduced herein (except for exhibits) as the Company's Annual Report for 2009 to its shareholders. The Form 10-K includes the Company's audited financial statements and other financial data and information, a description of the Company's business and properties and other pertinent information concerning the Company.

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

FORM 10-K

(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, 2009

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	**84-0637348**
(state or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
One Landmark Square, Stamford, CT	**06901**
(Address of principal executive offices)	(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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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, a non-accelerated filer or a small reporting company.

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 $23,336,482.

The number of shares outstanding of each class of the Registrant's Common Stock as of March 31, 2010 was 3,026,397 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 May 2010, are incorporated by reference in Part III hereof.

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PrimeEnergy Corporation

FORM 10-K ANNUAL REPORT
For the Fiscal Year Ended
December 31, 2009

PART I

Item 1. BUSINESS.

General

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

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

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

Exploration, Development and Recent Activities

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

As of December 31, 2009, the Company had net capitalized costs related to oil and gas properties of $173.8 million, including $1.3 million of undeveloped properties. Total expenditures for the acquisition, exploration and development of the Company's properties during 2009 were $17.5 million of which $136,000 related to exploration costs expensed during 2009. Proved reserves as of December 31, 2009, were 82 BCFe of gas which consisted of 79.63% proved developed reserves and 20.37% proved undeveloped reserves.

Significant 2009 activity

During 2009, the Company participated in drilling a total of 13 gross (11.74 net) wells, all of which were successful completions.

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 1,600 oil and gas wells, 376 through the Houston office, 314 through the Midland office, 412 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 2,467. 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 and trust unit holder interests.

Regulation

Regulation of Transportation and Sale of Natural Gas:

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended ("NGA"), the Natural Gas Policy Act of 1978, as amended ("NGPA"), and regulations promulgated thereunder 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 the Company 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.

The Company cannot accurately predict whether FERC's actions will achieve the goal of increasing competition in markets in which its 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, the Company does not believe that any action taken will affect them 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, the Company believes that the regulation of similarly situated intrastate natural gas transportation in any states in which it operates and ship natural gas on an intrastate basis will not affect operations in any way that is materially different from the effect of such regulation on 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, the Company believes that the regulation of oil transportation rates will not affect operations in any way that is materially different from the effect of such regulation on 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, the Company believes that access to oil pipeline transportation services generally will be available to them to the same extent as to 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 the Company owns and operates 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 the Company can produce from its wells and to limit the number of wells or the locations at which it 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 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, the Company is required to obtain prior MMS approval for any exploration plans it pursues and the development and production plans for these leases. MMS regulations also establish construction requirements for production facilities located on the Company's 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 the Company to suspend or terminate operations on a federal lease.

MMS also establishes the basis for royalty payments due under federal oil and natural gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and natural gas leases. The basis for royalty payments established by MMS and the state regulatory authorities is generally applicable to all federal and state oil and natural gas lessees. Accordingly, the Company believes that the impact of royalty regulation on operations should generally be the same as the impact on 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 the cost of doing business and, consequently, affects profitability. The Company's competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions affecting 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.	20%
Plains All American Inc.	59%
Gas Purchasers:	
Unimark LLC	13%
Cokinos Energy Corporation	30%
Atlas Pipeline Mid-Continent WestOK, LLC	17%

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

Environmental Matters

Various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA"), the Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act"), and the Federal Clean Air Act, as amended (the "Clean Air Act"), affect operations and costs. In particular, exploration, development and production operations, activities in connection with storage and transportation of oil and other hydrocarbons and 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 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 the Company's operations and financial position, as well as those in the oil and natural gas industry in general. While the Company believes that it is in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact, there is no assurance that this trend will continue in the future.

As with the industry generally, compliance with existing regulations increases the 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 ordinary operations, the Company may generate waste that may fall within CERCLA's definition of a "hazardous substance." The Company 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.

The Company currently owns or leases properties that for many years have been used for the exploration and production of oil and natural gas. Although the Company and its 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 the Company 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 the Company's control. These properties and wastes disposed on these properties may be subject to CERCLA and analogous state laws. Under these laws, the Company could be required:

- to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators;
- to clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

At this time, the Company does not believe that it is associated with any Superfund site and has 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 thereunder 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. The Company carries insurance coverage to meet these obligations, which the Company believes is customary for comparable companies in the oil and gas 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. The Company is not aware of any action or event that would subject them to liability under OPA and believes that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect.

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. The Company has coverage under the Region VI National Production Discharge Elimination System Permit for discharges associated with exploration and development activities. The Company takes 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, the Company is not required to comply with a substantial portion of RCRA's requirements because the 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 the Company is required to manage and dispose of and would cause them to incur increased operating expenses.

Clean Water Act. The Clean Water Act imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges.

Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. The Company believes that its 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. The Company currently owns and operates various underground injection wells. Failure to abide by the permits could subject the Company to civil and/or criminal enforcement. The Company believes that it is in compliance in all material respects with the requirements of applicable state underground injection control programs and 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 operations by restricting areas in which the Company may carry out future development and exploration projects and/or causing the Company 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. The Company's 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, the Company must certify that it will conduct its activities in a manner consistent with an applicable program.

Lead-Based Paints. Various pieces of equipment and structures owned by the Company 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 the Company needs 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 the Company 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. Operations utilize equipment that emits air pollutants subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Air emissions associated with offshore activities are projected using a matrix and formula supplied by MMS, which has primacy from the Environmental Protection Agency for regulating such emissions.

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

Employees

At March 8, 2010, the Company had 213 full-time and 11 part-time employees, 18 of whom were employed by the Company at its principal offices in Stamford, Connecticut, 37 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 169 employees who were primarily involved in the district operations of the Company in Houston and Midland, Texas, Oklahoma City, Oklahoma and Charleston, West Virginia.

Item 1A. RISK FACTORS.

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

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

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

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

- the price, availability and acceptance of alternative fuels; and
- overall economic conditions

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

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

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

- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

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

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

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

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

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

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and crude oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves. You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, 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 generally accepted accounting principles may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

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

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

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

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

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

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;

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

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

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

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

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

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

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

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

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

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

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record.

Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

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

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

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

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

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

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

Item 1B. UNRESOLVED STAFF COMMENTS.

The Company is a smaller reporting company and no response is required pursuant to this Item.

Item 2. PROPERTIES.

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

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

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

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

The following table sets forth the exploratory and development drilling experience with respect to wells in which the Company participated during the three years ended December 31, 2009.

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil	—	—	2	1.5	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	1	.375
Development:						
Oil	13	11.74	69	40.18	30	13.88
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total:						
Oil	13	11.74	71	41.68	30	13.88
Gas	—	—	—	—	—	—
Dry	—	—	—	—	1	.375
	13	11.74	71	41.68	31	14.255

Oil and Gas Production

As of December 31, 2009, 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	935	365
Gas Wells	1,171	513
Producing Acres	316,280.83	107,229.27

(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 acre 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, 2009. "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.

	2009	2008	2007
Oil (barrels)	640,000	658,000	561,000
Gas (Mcf)	7,129,000	8,899,000	11,312,000

The following table sets forth the Company's average sales price per barrel of crude oil and average sales prices per one thousand cubic feet ("Mcf") of gas, together with the Company's average production costs per unit of production for the three years ended December 31, 2009.

	2009	2008	2007
Average sales price per barrel	$59.16	84.43	66.94
Average sales price Per Mcf	$ 4.42	8.93	7.50
Average production costs per net equivalent barrel (1)	$18.32	19.92	14.24

(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, 2009. "Undeveloped acreage" is that acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

	Leasehold Interests		Mineral Interests		Royalty Interests	
State	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Colorado	—	—	799	23	—	—
Gulf of Mexico	85,696	54,288	—	—	—	—
Louisiana	—	—	—	—	295	1
Montana	—	—	14,304	60	—	—
Nebraska	—	—	2,554	331	—	—
North Dakota	—	—	640	1	—	—
Oklahoma	4,176	1,895	320	—	2,880	24
Texas	1,716	1,309	640	2	—	—
West Virginia	220	41	—	—	—	—
Wyoming	—	—	—	—	140	35
TOTAL	91,808	57,533	19,257	417	3,315	60

Reserves

The Company's interests, including the interests held by the Partnerships, 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, 2009. All of the Company's reserves are located within the continental United States. The following table summarizes the Company's oil and gas reserves at each of the respective dates (figures rounded):

	Reserve Category					
	Proved Developed		Proved Undeveloped		Total	
As of 12-31	Oil (bbls)	Gas (Mcf)	Oil (bbls)	Gas (Mcf)	Oil (bbls)	Gas (Mcf)
2007	5,640,000	58,814,000	952,000	2,598,000	6,592,000	61,412,000
2008	5,317,000	54,140,000	—	1,198,000	5,317,000	55,338,000
2009	4,476,000	38,389,000	1,611,000	7,024,000	6,087,000	45,413,000

The estimated future net revenue (using current prices and costs as of those dates) and the present value of future net revenue (at a 10% discount for estimated timing of cash flow) for the Company's proved developed and proved undeveloped oil and gas reserves at the end of each of the three years ended December 31, 2009, are summarized as follows (figures rounded):

	Proved Developed		Proved Undeveloped		Total			
As of 12-31	**Future Net Revenue**	**Present Value 10 Of Future Net Revenue**	**Future Net Revenue**	**Present Value 10 Of Future Net Revenue**	**Future Net Revenue**	**Present Value 10 Of Future Net Revenue**	**Present Value 10 Of Future Income Taxes**	**Standardized Measure of Discounted Cash flow**
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
2008	$206,400,000	132,654,000	1,502,000	1,515,000	207,902,000	134,169,000	17,635,000	116,534,000
2009	$178,272,000	110,613,000	44,792,000	10,388,000	223,064,000	121,001,000	18,260,000	102,742,000

The PV 10 Value represents the discounted future net cash flows attributable to the Company's proved oil and gas reserves before income tax, discounted at 10%. Although this measure is not in accordance with generally accepted accounting principles, the Company believes that the presentation of the PV 10 Value is relevant and useful to investors because it presents the discounted future net cash flow attributable to proved reserves prior to taking into account corporate future income taxes and the current tax structure. The Company uses this measure when assessing the potential return on investment related to oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to 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. The Company's reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of the Company's reserves.

In accordance with generally accepted accounting principles, product prices are determined using the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, 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 specifications and generally accepted accounting principles, changes in market prices subsequent to December 31 are not considered.

The range of Henry Hub daily gas prices per MMBTU during the year 2009 was a low of $1.92 and a high of $6.10 and the average was $3.95. The range during the first quarter of 2010 has been from $4.48 to $7.38, with an average of $5.45. The recent futures market prices have traded above $4.53 per MMBTU.

The range of NYMEX oil prices per barrel during the year 2009 was a low of $33.98 and a high of $81.37 and the average was $62.12. The range during the first quarter of 2010 has been from $71.19 to $83.18, with an average of $77.89. The recent futures market prices have fluctuated around $81.00.

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

Since January 1, 2010, 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.

District Information

The following table presents certain reserve, production and well information as of December 31, 2009.

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Offshore	Other	Total
Proved Reserves at Year End (Mmcfe)							
Developed	7,413	5,526	13,673	32,122	5,036	1,462	65,231
Undeveloped	—	—	—	16,336	351	—	16,687
Total	7,413	5,526	13,673	48,459	5,387	1,462	81,919
Average Daily Production (Mmcfe per day)	2	3	6	12	7	1	31
Gross Wells	732	468	700	425	19	77	2,421
Net Wells	377	167	267	156	10	14	991
Gross Operated Wells	498	295	412	314	17	64	1,600

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, 2009, 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 2009 was 2,216 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, 2009, we had 7.4 Bcfe of proved reserves (substantially all natural gas) in the Appalachian region, constituting 9.0% 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 468 wells (167 net) in the Gulf Coast region as of December 31, 2009, of which 295 wells are operated by us. Average daily production in 2009 was 3,229 Mcfe. At December 31, 2009, we had 5.5 Bcfe of proved reserves (69.3% natural gas) in the Gulf Coast region, which represented 6.7% of our total proved reserves.

Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. As of December 31, 2009, we had 700 wells (267 net) in the Mid-Continent area, of which 412 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 2009 was 6,288 Mcfe. At December 31, 2009, we had 13.7 Bcfe of proved reserves (67.2% natural gas) in the Mid-Continent area, or 16.7% 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, 2009, we had 425 wells (156 net) in the West Texas area, of which 314 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 2009 was 11,749 Mcfe. At December 31, 2009, we had 48.4 Bcfe of proved reserves (38.1% natural gas) in the West Texas area, or 59.2% of our total proved reserves. This region is managed from our office in Midland, Texas.

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 19 wells (10 net) in the Offshore Gulf of Mexico region as of December 31, 2009, of which 17 wells are operated by us. Average daily production in 2009 was 6,746 Mcfe. At December 31, 2009, we had 5.4 Bcfe of proved reserves (substantially all natural gas) in the Offshore Gulf of Mexico region, which represented 6.6% of our total proved reserves.

Acreage subject to expiration in the next three years

	2010		2011		2012	
State	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
GULF OF MEXICO	—	—	28,800	21,600	—	—
OKLAHOMA	170	85	—	—	—	—
TEXAS	—	24	—	—	—	—
NEW MEXICO	320	87	—	—	—	—
WEST VIRGINIA	—	11	—	—	—	—
COLORADO	211	—	—	—	—	—
TOTAL	701	207	28,800	21,600	—	—

Item 3. LEGAL PROCEEDINGS.

Not applicable

Item 4. RESERVED.

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, 2009, were as follows:

2009	High	Low	2008	High	Low
First Quarter	$55.97	$24.46	First Quarter	$58.00	$52.08
Second Quarter	$53.22	$32.69	Second Quarter	$64.50	$52.00
Third Quarter	$36.74	$23.58	Third Quarter	$82.38	$50.68
Fourth Quarter	$38.74	$27.02	Fourth Quarter	$77.62	$44.63

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 31, 2010, was 663.

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, the Company announced that the Board of Directors authorized a stock repurchase program whereby the Company may purchase outstanding shares of the 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, 2009, a total of 2,514,359 shares has been repurchased under this program for $34,074,279 at an average price of $13.55 per share. Additional purchases of shares may occur as market conditions warrant. The Company expects future purchases will be funded with internally generated cash flow or from working capital.

2009 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Program at Month-End
January	1,803	$42.82	194,920
February	2,209	34.18	192,711
March	1,824	39.38	190,887
April	946	45.77	189,941
May	—	—	189,941
June	—	—	189,941
July	—	—	189,941
August	—	—	189,941
September	—	—	189,941
October	1,400	31.06	188,541
November	1,300	33.67	187,241
December	1,600	36.50	185,641
Total/Average/Remainder	11,082	$37.31	

Item 6. SELECTED FINANCIAL DATA

The Company is a smaller reporting company and no response is required pursuant to this Item.

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

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

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.

Liquidity And Capital Resources:

Cash flow provided by operations for the year ended December 31, 2009, was $34 million, compared to $84 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.

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 2009 was $565 thousand. The Company expects continue spending under these programs in 2010.

The Company currently maintains two credit facilities totaling $360 million, with a combined current borrowing base of $105.5 million. The bank reviews the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a redetermined estimate of proved oil and gas reserves. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial covenants defined in the agreement. We are currently in compliance with these financial covenants. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable.

During the second quarter of 2008, the Company's offshore subsidiary arranged a subordinated credit facility with a private lender controlled by a director of the Company. The facility provides availability of $50 million and is secured by properties released by the bank and pledged under this agreement. The current advances under this credit facility are $20 million due January 2012.

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

Results of Operations:

2009 as compared to 2008

The Company had a net loss of $23,679,000 in 2009 as compared to net income of $541,000 in 2008. The significant components of net income are discussed below.

Oil and gas sales were $69,343,000 in 2009 as compared to $135,036,000 in 2008. A chart summarizing oil and gas production and revenue is presented below.

	2009	2008	Increase (Decrease)
Barrels of Oil Produced	640,000	658,000	(18,000)
Average Price Received (rounded, including the impact of derivatives)	$ 59.16	$ 84.43	$ (25.27)
Oil Revenue	$37,860,000	$ 55,554,000	$(17,694,000)
Mcf of Gas Produced	7,129,000	8,899,000	(1,770,000)
Average Price Received (rounded, including the impact of derivatives)	$ 4.42	$ 8.93	$ (4.51)
Gas Revenue	$31,483,000	$ 79,482,000	$(47,999,000)
Total Oil & Gas Revenue	$69,343,000	$135,036,000	$(65,693,000)

Oil & gas prices received excluding the impact of derivatives were:

	2009	2008	Increase (Decrease)
Oil Price	$56.80	$95.74	$(38.94)
Gas Price	$ 4.42	$ 9.09	$ (4.67)

Changes in Production related to gas are primarily due to the natural decline in our offshore properties. The oil production remained relatively stable as a result of the additional properties added throughout 2008.

Field service income decreased by 32.65% to $16,627,000 in 2009 from $24,687,000 in 2008 as a result of reduced utilization of equipment combined with rate decreases.

Field service expense decreased by 26.66% to $14,614,000 in 2009 from $19,927,000 in 2008. This decrease is the result of reduced labor and operating costs associated with the drop in equipment utilization in 2009.

Lease operating expenses decreased by 21.46% to $33,490,000 in 2009 from $42,643,000 in 2008 due to overall price decreases in oil field services combined with reduced production taxes related to commodity prices.

General and administrative expenses decreased by 18.29% to $11,858,000 in 2009 from $14,512,000 in 2008. This decrease is primarily due to reductions in personnel costs.

Depreciation and depletion decreased by 28.42% to $55,741,000 in 2009 from $77,869,000 in 2008. This decrease is primarily related to the decrease in offshore production in 2009.

Interest expense decreased by 7.46% to $7,373,000 in 2009 from $7,967,000 in 2008. This decrease is due to lower outstanding debt balances during the year and slightly lower average interest rates. The average interest rates paid on outstanding bank borrowings subject to interest during 2009 and 2008 were 5.59% and 5.64% respectively. As of December 31, 2009 and 2008, the total outstanding borrowings were $113,995,000 and $124,140,000, respectively.

Income tax benefit of $12,305,000 was recorded for 2009, including a reduction of $9,173,000 in the Company's deferred tax liability. The Company expects to have a net operating loss on the 2009 federal income tax return, and to carry this loss back to offset previous year tax liabilities and receive a refund of approximately $2,466,000.

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

The Company is a smaller reporting company and no response is required pursuant to this Item.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements and supplementary information included in this Report are described in the Index to Consolidated 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.

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 Exchange Act. 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, 2009. 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 the Company maintained effective internal control over financial reporting as of December 31, 2009.

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, 2009 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company's Directors, nominees for Directors and executive officers is included in the Company's definitive proxy statement relating the Company's Annual Meeting of Stockholders to be held in May, 2010 which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2009, 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 May, 2010, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2009, 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 May, 2010, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2009, 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 May, 2010, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2009, 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 May, 2010, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2009, and which is incorporated herein by reference.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this Report:

1. Financial statements (Index to Consolidated Financial Statements at page F-1 of this Report)
2. Financial Statement Schedules (Index to Consolidated Financial Statements—Supplementary Information at page F-1 of this Report)
3. Exhibits:

Exhibit No.	
3.1	Restated Certificate of Incorporation of PrimeEnergy Corporation (effective July 1, 2009) (Incorporated by reference to Exhibit 3.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009)
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, 2006) (1)
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)

10.22.5.2	First Amendment to Amended and Restated Credit Agreement between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank, FSB as Agent and Letter of Credit Issuer BNP Paribas, as Co-Documentation Agent and JPMorgan Chase Bank, N.A. as Co-Documentation Agent and the Lenders Signatory Hereto, dated July 17, 2007. (Incorporated by reference to Exhibit 10.22.5.2 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2008)
10.22.5.3	Second Amendment to Amended and Restated Credit Agreement between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank, FSB as Agent and Letter of Credit Issuer BNP Paribas, as Co-Documentation Agent and JPMorgan Chase Bank, N.A. as Co-Documentation Agent and the Lenders Signatory Hereto, dated October 9, 2007. (Incorporated by reference to Exhibit 10.22.5.3 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2008)
10.22.5.4	Third Amendment to Amended and Restated Credit Agreement between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank, FSB as Agent and Letter of Credit Issuer and the Lenders Signatory Hereto, effective January 22, 2008. (Incorporated by reference to Exhibit 10.22.5.4 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2008)
10.22.5.5	Fourth Amendment to Amended and Restated Credit Agreement between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank, FSB as Agent and Letter of Credit Issuer and the Lenders Signatory Hereto, effective February 8, 2008. (Incorporated by reference to Exhibit 10.22.5.5 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2008)
10.22.5.6	Fifth Amendment to Amended and Restated Credit Agreement between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Guaranty Bank, FSB as Agent and Letter of Credit Issuer and the Lenders Signatory Hereto, effective October 30, 2008. (Incorporated by reference to Exhibit 10.22.5.6 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2008)
10.22.5.7	Sixth Amendment to 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 the Lenders Signatory Hereto, effective June 19, 2009. (Incorporated by reference to Exhibit 10.22.5.7 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009)
10.22.5.8	Seventh Amendment to 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 Compass Bank (successor in interest to Guaranty Bank, FSB), as Agent and Letter of Credit Issuer and the Lenders Signatory Hereto, effective as of March 1, 2010 (filed herewith)
10.23.2	Amended and Restated Security Agreement between PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company, (debtor) and Guaranty Bank, FSB as Agent (secured party) December 28, 2006 (Incorporated by reference to Exhibit 10.23.2 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006)

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)
10.23.9	Ratification of and Amendment to Mortgage, Deed of Trust, Security Agreement, Financing Statement and Assignment of Production, dated effective February 24, 2010, by and between PrimeEnergy Corporation and PrimeEnergy Management Corporation and Compass Bank (successor in interest to Guaranty Bank, FSB) (filed herewith)
10.25	Credit Agreement dated as of June 1, 2006 (but effective for all purposes as of August 22, 2005), between Prime Offshore L.L.C. as Borrower and PrimeEnergy Corporation as Lender (Incorporated by reference to Exhibit 10.25 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)
10.26.2	Amended and Restated Credit Agreement among Prime Offshore L.L.C. between Guaranty Bank, FSB, as agent and the Lenders party hereto effective March 31, 2008. (Incorporated by reference to Exhibit 10.26.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2008)
10.26.3	Consent, Waiver and First Amendment to Amended and Restated Credit Agreement Among Prime Offshore L.L.C., Guaranty Bank, FSB, as Agent and the Lenders Party Hereto, effective June 30, 2009. (Incorporated by reference to Exhibit 10.26.3 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009)
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 from Prime Offshore L.L.C. for the benefit of Guaranty Bank, FSB, Agent, effective June 30, 2009. (Incorporated by reference to Exhibit 10.27.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009)
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)
10.27.3	Subordinated Promissory Note dated effective March 31, 2008 in the face principal amount of up to $50,000,000 executed by Prime Offshore L.L.C. and payable to Artic Management Corporation. (Incorporated by reference to Exhibit 10.27.3 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2008)
10.27.3.1	Loan Modification effective 30th day of June, 2009 by and between Artic Management Corporation, Prime Offshore L.L.C. and PrimeEnergy Corporation. (Incorporated by reference to Exhibit 10.27.3.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009)
10.27.4	Mortgage, Deed of Trust, Security Agreement, Financing Statement and Assignment of Production Dated effective as of March 31, 2008 from Prime Offshore L.L.C. to Mathias Eckenstein TTEE for Artic Management Corporation (first lien). (Incorporated by reference to Exhibit 10.27.4 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2008)
10.27.5	Mortgage, Deed of Trust, Security Agreement, Financing Statement and Assignment of Production Dated effective as of March 31, 2008 from Prime Offshore L.L.C. to Mathias Eckenstein TTEE for Artic Management Corporation (second lien). (Incorporated by reference to Exhibit 10.27.5 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2008)
10.27.6	Pledge Agreement dated as effective March 31, 2008 between Prime Offshore L.L.C. and Artic Management Corporation (General Partner Interest in FWOE Partners L.P.) (Incorporated by reference to Exhibit 10.27.6 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2008)
10.27.7	Pledge Agreement made effective June 30, 2009, by and between Prime Offshore L.L.C. and Guaranty Bank, FSB, as Agent. (Incorporated by reference to Exhibit 10.27.7 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009)
10.27.8	Subordination of Liens and Security Interests effective June 30, 2009, by Artic Management Corporation for the benefit of Guaranty Bank, FSB, as Agent. (Incorporated by reference to Exhibit 10.27.8 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009
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)
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)

31.1 Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).

31.2 Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).

32.1 Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

32.2 Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 15th day of April, 2010.

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 15th day of April, 2010.

/s/ CHARLES E. DRIMAL, JR. Charles E. Drimal, Jr.	Director and President; The Principal Executive Officer
/s/ BEVERLY A. CUMMINGS Beverly A. Cummings	Director, Vice President and Treasurer; The Principal Financial Officer
/s/ LYNNE PIZOR Lynne Pizor	Controller; The Principal Accounting Officer

/s/ MATTHIAS ECKENSTEIN Matthias Eckenstein	Director	/s/ CLINT HURT Clint Hurt	Director
/s/ H. GIFFORD FONG H. Gifford Fong	Director	/s/ JAN K. SMEETS Jan K. Smeets	Director
/s/ THOMAS S.T. GIMBEL Thomas S.T. Gimbel	Director		

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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 sheet of PrimeEnergy Corporation and Subsidiaries (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, comprehensive income, and cash flows for each of the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of PrimeEnergy Corporation and Subsidiaries as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the years then ended in conformity with accounting principles generally accepted in the United States of America.

/s/ Pustorino, Puglisi & Co

PUSTORINO, PUGLISI & CO., LLP
New York, New York
April 15, 2010

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET, December 31, 2009 and 2008

	2009	2008
ASSETS:		
Current assets:		
Cash and cash equivalents	$ 11,779,000	$ 11,808,000
Restricted cash and cash equivalents	5,497,000	8,027,000
Accounts receivable, net	13,876,000	18,257,000
Due from related parties	30,000	678,000
Prepaid expenses	1,100,000	1,302,000
Derivative contracts	657,000	1,755,000
Inventory at cost	1,871,000	4,532,000
Deferred income taxes	838,000	30,000
Total current assets	35,648,000	46,389,000
Property and equipment, at cost:		
Proved oil and gas properties at cost	441,035,000	427,174,000
Unproved oil and gas properties at cost	1,322,000	2,409,000
Less: Accumulated depletion and depreciation	268,514,000	217,434,000
	173,843,000	212,149,000
Field and office equipment	19,462,000	19,513,000
Less: Accumulated depreciation	12,199,000	11,197,000
	7,263,000	8,316,000
Total net property and equipment	181,106,000	220,465,000
Other assets	764,000	976,000
Total assets	$217,518,000	$267,830,000
LIABILITIES AND STOCKHOLDERS' EQUITY:		
Current liabilities:		
Current bank debt	$ 7,000,000	$ 16,970,000
Accounts payable	21,291,000	26,715,000
Current portion of asset retirement and other long-term obligations	3,374,000	1,461,000
Derivative liability short term	2,288,000	387,000
Accrued liabilities	5,985,000	10,477,000
Due to related parties	450,000	233,000
Total current liabilities	40,388,000	56,243,000
Long-term bank debt	86,955,000	87,170,000
Indebtedness to related parties	20,000,000	20,000,000
Asset retirement obligations	16,862,000	18,650,000
Derivative liability long term	2,892,000	146,000
Deferred income taxes	16,635,000	25,688,000
Total liabilities	183,732,000	207,897,000
Stockholders' equity—PrimeEnergy:		
Common stock, $.10 par value; 2009: Authorized: 4,000,000 shares, issued: 3,836,397 shares, outstanding: 3,032,097 shares; 2008: Authorized: 10,000,000 shares, issued: 7,694,970 shares, outstanding: 3,047,564 shares	383,000	769,000
Paid in capital	5,465,000	11,024,000
Retained earnings	43,725,000	73,426,000
Accumulated other comprehensive income (loss)	(214,000)	1,009,000
	49,359,000	86,228,000
Treasury stock, at cost; 2009: 804,300 shares; 2008: 4,647,316 shares	(25,417,000)	(36,940,000)
Total stockholders' equity—PrimeEnergy	23,942,000	49,288,000
Non-controlling interest	9,844,000	10,645,000
Total stockholders' equity	33,786,000	59,933,000
Total liabilities and stockholders' equity	$217,518,000	$267,830,000

See accompanying notes to the consolidated financial statements.

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS
for the years ended December 31, 2009 and 2008

	2009	2008
Revenue:		
Oil and gas sales	$ 69,343,000	$135,036,000
Field service income	16,627,000	24,687,000
Administrative overhead fees	7,972,000	9,255,000
Loss on derivative instruments	(3,966,000)	—
Other income	16,000	360,000
Total revenue	89,992,000	169,338,000
Costs and expenses:		
Lease operating expense	33,490,000	42,643,000
Field service expense	14,614,000	19,927,000
Depreciation, depletion and amortization	55,741,000	77,869,000
Loss on settlement of asset retirement obligation	2,038,000	—
General and administrative expense	11,858,000	14,512,000
Exploration costs	136,000	649,000
Total costs and expenses	117,877,000	155,600,000
Gain on sale and exchange of assets	236,000	392,000
Income (loss) from operations	(27,649,000)	14,130,000
Other income and expenses:		
Less: Interest expense	7,373,000	7,967,000
Add: Interest income	52,000	381,000
Income (loss) before provision (benefit) for income taxes	(34,970,000)	6,544,000
Provision (benefit) for income taxes	(12,305,000)	59,000
Net income (loss)	(22,665,000)	6,485,000
Less: Net income attributable to non-controlling interest	1,014,000	5,944,000
Net income (loss) attributable to PrimeEnergy	$ (23,679,000)	$ 541,000
Basic income (loss) per common share	$ (7.79)	$ 0.18
Diluted income (loss) per common share	$ (7.79)	$ 0.14

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

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
for the years ended December 31, 2009 and 2008

	Common Stock		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Stockholders' Equity— PrimeEnergy	Non-Controlling Interest	Total Stockholders' Equity
	Shares	Amount							
Balance at January 1, 2008	7,694,970	$ 769,000	$11,024,000	$ 72,885,000	$(3,618,000)	$(32,388,000)	$ 48,672,000	$12,929,000	$ 61,601,000
Purchase 88,832 shares of common stock						(4,552,000)	(4,552,000)		(4,552,000)
Net income				541,000			541,000	5,944,000	6,485,000
Other comprehensive income, net of taxes					4,627,000		4,627,000		4,627,000
Purchase of non-controlling interest							—	(481,000)	(481,000)
Distributions to non-controlling interest							—	(7,747,000)	(7,747,000)
Balance at December 31, 2008	7,694,970	$ 769,000	$11,024,000	$ 73,426,000	$ 1,009,000	$(36,940,000)	$ 49,288,000	$10,645,000	$ 59,933,000
Purchase 11,082 shares of common stock						(413,000)	(413,000)		(413,000)
Retire 3,858,573 shares of treasury stock	(3,858,573)	(386,000)	(5,528,000)	(6,022,000)		11,936,000	—		—
Net loss				(23,679,000)			(23,679,000)	1,014,000	(22,665,000)
Other comprehensive loss, net of taxes					(1,223,000)		(1,223,000)		(1,223,000)
Purchase of non-controlling interest			(31,000)				(31,000)	(120,000)	(151,000)
Distributions to non-controlling interest							—	(1,695,000)	(1,695,000)
Balance at December 31, 2009	3,836,397	$ 383,000	$ 5,465,000	$ 43,725,000	$ (214,000)	$(25,417,000)	$ 23,942,000	$ 9,844,000	$ 33,786,000

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

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Years Ended December 31,	
	2009	2008
Net income (loss)	$(23,679,000)	$ 541,000
Other comprehensive income (loss), net of taxes:		
Reclassification adjustment for settled contracts, net of taxes of $230,000 and $3,064,000, respectively	408,000	5,446,000
Changes in fair value of hedge positions, net of taxes of $917,000 and $461,000, respectively	(1,631,000)	(819,000)
Total other comprehensive income (loss)	(1,223,000)	4,627,000
Comprehensive income (loss)	(24,902,000)	5,168,000
Less: Comprehensive income attributable to non-controlling interest	(1,014,000)	(5,944,000)
Comprehensive income (loss) attributable to PrimeEnergy	$(23,888,000)	$11,112,000

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

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS
for the years ended December 31, 2009 and 2008

	2009	2008
Cash flows from operating activities:		
Net income (loss)	$(23,679,000)	$ 541,000
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Non-controlling interest in earnings of partnerships	1,014,000	5,944,000
Depreciation, depletion, amortization and accretion on discounted liabilities	55,741,000	77,869,000
Gain on sale of properties	(236,000)	(392,000)
Unrealized loss on derivative instruments	3,966,000	—
Provision for deferred income taxes	(11,972,000)	(1,387,000)
Loss on settlement of asset retirement obligations	2,038,000	—
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	6,847,000	3,056,000
(Increase) decrease in due from related parties	649,000	(996,000)
(Increase) decrease in inventories	2,660,000	115,000
(Increase) decrease in prepaid expenses and other assets	454,000	(831,000)
Increase (decrease) in accounts payable	(2,697,000)	1,551,000
Increase (decrease) in accrued liabilities	(943,000)	(1,033,000)
Increase (decrease) in due to related parties	218,000	(697,000)
Net cash provided by operating activities	34,060,000	83,740,000
Cash flows from investing activities		
Capital expenditures, including exploration expense	(18,020,000)	(55,034,000)
Proceeds from sale of properties and equipment	236,000	392,000
Net cash used in investing activities	(17,784,000)	(54,642,000)
Cash flows from financing activities		
Purchase of stock for treasury	(413,000)	(4,552,000)
Purchase of non-controlling interests	(152,000)	(481,000)
Increase in long-term bank debt and other long-term obligations	43,100,000	116,295,000
Repayment of long-term bank debt and other long-term obligations	(57,147,000)	(148,459,000)
Distribution to non-controlling interest	(1,693,000)	(5,466,000)
Net cash used in financing activities	(16,305,000)	(42,663,000)
Net (decrease) in cash and cash equivalents	(29,000)	(13,565,000)
Cash and cash equivalents at the beginning of the year	11,808,000	25,373,000
Cash and cash equivalents at the end of the year	$ 11,779,000	$ 11,808,000
Supplemental disclosures:		
Income taxes paid during the year	$ 463,000	$ 395,000
Net income tax refunds received during the year	$ 797,000	$ —
Interest paid during the year	$ 7,373,000	$ 7,967,000

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

PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Operations and Significant Accounting Policies

Nature of Operations:

PrimeEnergy Corporation ("PEC"), a Delaware corporation, was organized in March 1973 and is engaged in the development, acquisition and production of oil and natural gas properties. PrimeEnergy Corporation and its subsidiaries are herein referred to as the "Company." 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 1,600 wells and owns non-operating interests in over 821 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 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 are controlled by the Company. 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 are not controlled by the Company. For those entities which are proportionately consolidated the 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 the ownership percentage of Partnership reserve reports. DD&A expense and evaluation of impairment may differ from the Partnership as the Company's 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. Subsequent events have been evaluated through April 15, 2010, the date that the consolidated financial statements were issued.

Use of Estimates:

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

Estimates of oil and gas reserves, as determined by independent petroleum engineers, are continually subject to revision based on price, production history and other factors. Depletion expense, which is computed based on the units of production method, could be significantly impacted by changes in such estimates. Additionally, generally accepted accounting principles require 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.

Fair Value:

The Company follows the authoritative guidance that establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by generally accepted accounting principles to be measured at fair value. The guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. The guidance establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to level 1 measurements and the lowest priority to level 3 measurements, and accordingly, level 1 measurement should be used whenever possible.

Asset Retirement Obligation:

Effective January 1, 2003, the Company adopted the accounting standard for asset retirement obligations. The asset retirement obligation primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate producing properties (including removal of 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 at its inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Income Taxes:

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to turn around. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

General and Administrative Expenses:

General and administrative expenses represent cost and expenses associated with the operation of the Company.

Earnings (Loss) Per Common Share:

Basic earnings (loss) per share are computed by dividing earnings (loss) 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 in gain periods.

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 applicable accounting standards for derivative instruments and hedging activities. Such standards require that applicable derivative instruments 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 applicable effectiveness guidelines, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in the statement of operations.

Recently Adopted Accounting Standards:

In July 2009, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (the Codification), "Generally Accepted Accounting Principles," establishing the accounting standards codification and the hierarchy of generally accepted accounting principles (GAAP) as the sole source of authoritative non-governmental U.S. GAAP. The Codification was not intended to change U.S. GAAP; however, references to various accounting pronouncements and literature will now differ from what was previously being used in practice. Authoritative literature is now referenced by topic rather than by type of standard. As of July 1, 2009, the FASB no longer issues Statements, Interpretations, Staff Positions or Emerging Issues Task Force (EITF) Abstracts. The FASB now communicates new accounting standards by issuing an Accounting Standards Update (ASU). All guidance in the codification has an equal level of authority. The Codification is effective for financial statements that cover interim and annual periods ending after September 15, 2009, and supersedes all accounting standards in U.S. GAAP, aside from those issued by the SEC. There was no impact on the Company's financial position, results of operations or cash flows as a result of the Codification.

In January 2010, the FASB issued an ASU, Oil and Gas Reserve Estimation and Disclosures, which aligns the FASB's oil and gas reserve estimation and disclosure requirements with the requirements in SEC Release No. 33-8955, "Modernization of Oil and Gas Reporting Requirements" (the "Release") issued in December 2008. The ASU is effective for reporting periods ending on or after December 31, 2009. The provisions include changes to pricing used to estimate reserves (with the use of an average of the first-day-of-the-month price for the 12-month period, rather than a year-end price for determining whether reserves can be produced economically), an expanded definition of oil and gas producing activities to include nontraditional resources, and amended definitions of key terms such as "reliable technology" and "reasonable certainty" which are used in estimating proved oil and gas reserve quantities. The primary objectives of the revisions are to increase the transparency and information value of reserve disclosures and improve comparability among oil and gas companies. The adoption of these requirements did not significantly impact the reported value of the Company's reserves or its financial statements.

On January 1, 2009, the Company adopted the guidance "Non-controlling Interests in Consolidated Financial Statements" to establish accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. This guidance defines a non-controlling interest, previously called a minority interest, as the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. The guidance requires, among other items, that a non-controlling interest be included in the consolidated statement of financial position within equity separate from the parent's equity; consolidated net income to be reported at amounts inclusive of both the parent's and non-controlling interest's shares and, separately, the amounts of consolidated net income attributable to the parent and non-controlling interest all on the consolidated income statement; and if a subsidiary is deconsolidated, any retained non-controlling equity investment in the former subsidiary be measured at fair value and a gain or loss be recognized in net income based on such fair value. The adoption of the guidance resulted in changes to the Company's presentation for non-controlling interests but did not have a material impact on the Company's results of operations and financial condition. Certain prior period balances have been restated to reflect the changes required by the guidance.

In August 2009, the FASB issued guidance on the measurement of liabilities at fair value. The guidance provides clarification that in circumstances in which a quoted market price in an active market for an identical liability is not available, an entity is required to measure fair value using a valuation technique that uses the quoted price of an identical liability when traded as an asset or, if unavailable, quoted prices for similar liabilities or similar assets when traded as assets. If none of this information is available, an entity should use a valuation technique in accordance with existing fair valuation principles. There was no impact on the Company's financial position, results of operations or cash flows as a result of the adoption of this guidance.

In April 2009, the FASB amended guidance regarding determining fair value when the volume and level of activity for an asset or liability has significantly decreased and identifying transactions that are not orderly. If an entity determines that either the volume or level of activity for an asset or liability has significantly decreased from normal conditions, or that price quotations or observable inputs are not associated with orderly transactions, increased analysis and management judgment will be required to estimate fair value. The objective in fair value measurement remains unchanged from what is prescribed in the guidance and should be reflective of the current exit price. Disclosures in interim and annual periods must include inputs and valuation techniques used to measure fair value, along with any changes in valuation techniques and related inputs during the period. In addition, disclosures for debt and equity securities must be provided on a more disaggregated basis. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on the Company's financial position, results of operations or cash flows.

In April 2009, the FASB amended "Financial Instruments" to require disclosures about fair value of financial instruments for publicly traded companies for both interim and annual periods. Historically, these disclosures were only required annually. The interim disclosures are intended to provide financial statement users with more timely and transparent information about the effects of current market conditions on an entity's financial instruments that are not otherwise reported at fair value. These amendments became effective for interim reporting periods ending after June 15, 2009. Comparative disclosures are only required for periods ending after the initial adoption. There was no material impact on the Company's financial position, results of operations or cash flows as a result of the adoption.

In April 2009, the FASB amended the other-than-temporary impairment guidance for debt securities in "Investments-Debt and Equity Securities" to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. There were no amendments made to the recognition and measurement guidance for equity securities, but a new method of recognizing and reporting for debt securities was established. Disclosure requirements for impaired debt and equity securities have been expanded significantly and are now required quarterly, as well as annually. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on the Company's financial position, results of operations or cash flows. Comparative disclosures are only required for periods ending after the initial adoption.

In June 2009, the FASB amended "Subsequent Events" to require entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. These amendments became effective for interim and annual periods ending after June 15, 2009 and did not have any impact on the Company's financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements:

In January 2010, the FASB issued changes clarifying existing disclosure requirements for fair value measurements and requiring gross presentation of activities within the reconciliation for the period, whereby entities must present separately information about purchases, sales, issuances and settlements. The update also added a new requirement to disclose fair value transfers in and out of Levels 1 and 2 and describe the reasons for the transfers. These changes will be effective for financial statements issued for the first interim or annual reporting period beginning after December 15, 2009, except for gross presentation of the Level 3 reconciliation for the period, which will become effective for annual reporting periods beginning after December 15, 2010. These changes are not expected to have a material impact on the Company's financial position, results of operations or cash flows.

In June 2009, the FASB issued changes to "Transfers and Servicing" which will require entities to provide more information about sales of securitized financial assets and similar transactions, particularly if the seller retains some risk to the assets. These changes will be effective at the beginning of the first fiscal year beginning after November 15, 2009. As the Company does not anticipate having any of these types of transactions in the near future, these changes are not expected to have any impact on its financial position, results of operations or cash flows.

In December 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting," which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 will be required to price proved oil and gas reserves using the un-weighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. The Company is currently evaluating what impact Release No. 33-8995 may have on its financial position, results of operations or cash flows.

2. Acquisitions and Dispositions

Historically the Company has repurchased the interests of the partners and trust unit holders in certain of the Partnerships, which consist primarily of oil and gas interests. The Company purchased such interests in an amount totaling $152,000 in 2009 and $481,000 in 2008.

3. Additional Balance Sheet Information

Accounts receivable at December 31, 2009 and 2008 consisted of the following:

	December 31,	
	2009	2008
Joint interest billing	$ 2,411,000	$ 2,244,000
Trade receivables	1,565,000	7,270,000
Oil and gas sales	7,774,000	8,426,000
Refundable prior years income taxes (note 9)	2,466,000	—
Other	83,000	608,000
	14,299,000	18,548,000
Less: Allowance for doubtful accounts	423,000	291,000
Total	$13,876,000	$18,257,000

Accounts payable at December 31, 2009 and 2008 consisted of the following:

	December 31,	
	2009	2008
Trade	$ 5,862,000	$ 9,753,000
Royalty and other owners	9,920,000	13,215,000
Other	5,509,000	3,747,000
Total	$21,291,000	$26,715,000

Accrued liabilities at December 31, 2009 and 2008 consisted of the following:

	December 31,	
	2008	2008
Compensation and related expenses	$2,009,000	$ 2,185,000
Property costs	2,137,000	5,582,000
Income tax	170,000	504,000
Other	1,669,000	2,206,000
	$5,985,000	$10,477,000

4. Property and Equipment

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. There was no interest capitalized during 2009 or 2008.

5. Long-Term Debt

Bank Debt:

Prior to August 21, 2009 the Company's long-term debt consisted of an onshore facility owed to a syndicate of banks and an offshore facility owed to one principal lender. The agent for the syndicate of banks and principal lender was Guaranty Bank. On August 21, 2009, Guaranty Bank was closed by the Office of Thrift Suspension.

Subsequently, the Federal Deposit Insurance Corporation (FDIC) was named Receiver. Loan administration and all deposit accounts were transferred to BBVA Compass from the FDIC at that time. BBVA Compass became the agent for the syndicate of banks holding the onshore credit facility and the lender for the offshore facility.

The Company has revolving lines of credit up to a total of $360 million, consisting of a $200 million credit facility (the offshore facility) and a $160 million credit facility through a syndicate of banks (the onshore facility). The offshore facility's maturity date is October 1, 2010 and the onshore credit facility matures April 1, 2011. Availability under the credit facilities is based on the loan value assigned to PEC's oil and gas properties. The determination of the borrowing base is made by the lenders taking into consideration the estimated value of PEC's oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. This process involves reviewing PEC's estimated proved reserves and their valuation. The borrowing base is re-determined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redetermination. In addition, PEC and the lenders each have discretion at any time to have the borrowing base re-determined. A revision to PEC'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, PEC would be required to repay the excess amount within a prescribed period. If the Company is 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 a minimum current ratio, tangible net worth, debt coverage ratio and interest coverage ratio, as defined, 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. PEC also pledged the stock of several subsidiaries to the lenders to secure the credit facilities.

As of December 31, 2009, the onshore facilities borrowing base was $98 million, including a monthly reduction of $2 million which began December 1, 2009. As of December 31, 2009 the offshore facilities borrowing base was $7 million with a monthly reduction of $500 thousand which began in August 2009. The Company's borrowing rates in both facilities have a floor of 2% plus applicable margin rates that vary from 3% to 5% depending on which facility, the value of current borrowings and the actual available borrowing base. Subsequent to year end on March 1, 2010, the Company amended its onshore credit facility to formally include BBVA Compass as agent of the syndicate of banks holding the facility. At this time the borrowing base was increased to $100 million with terms including a reduction to the availability of the borrowing beginning June 1, 2010 in the amount of $2 million.

At December 31, 2009, the borrowing base available was $98 million and the outstanding balance of the Company's bank debt was $86.955 million under the onshore credit facility at a weighted average interest rate of 5.61%. Under the offshore credit facility the outstanding balance was $7 million, with no further availability, at a weighted average interest rate of 5.36%. Total outstanding bank debt was $93.955 million at December 31, 2009. The combined weighted average interest rates paid on outstanding bank borrowings subject to interest at the bank's base rate and on outstanding bank borrowings bearing interest based upon the LIBO rate were 5.59% during 2009 as compared to 5.64% during 2008.

The Company entered into interest rate hedge agreements to help manage interest rate exposure. These contracts include interest rate swaps. Interest rate swap transactions generally involve the exchange of fixed and floating rate interest payment obligations without the exchange of the underlying principal amounts. The Company entered into interest swap agreements for a period of two years, which will expire in April 2010, related to $60 million of Company bank debt resulting in a fixed rate of 2.375% plus the Company's current applicable margin. The underlying debt contracts above are re-priced quarterly based upon the three-month LIBO rates, the Company's floor of 2% and the applicable margin per the onshore credit facility.

Indebtedness to related parties—non-current:

During the second quarter 2008, the Company's offshore subsidiary entered into a subordinated credit facility with a private lender with an availability of $50 million. The private lender has specific collateral pledged under a separate credit agreement. The private lender is controlled by a director of the Company. Effective June 30, 2009, the private lender agreed to release the pledged collateral under this credit facility in favor of the offshore credit facility in exchange for a second lien position on all of the assets of the offshore subsidiary and a pledge from PEC to pay the outstanding balance under the facility in full after PEC's current bank debt is paid off and not take on any additional debt on its existing asset base. This amended facility will mature in January 2012, which will be accelerated if there is a change in control or management of PrimeEnergy Corporation, and bears interest at a rate of 10% per annum. As of December 31, 2009 advances from this facility amounted to $20 million.

6. Commitments

Operating Leases:

The Company has several non-cancelable operating leases, primarily for rental of office space, that have a term of more than one year. The future minimum lease payments for the operating leases are as follows.

	Operating Leases
2010	$ 743,000
2011	384,000
2012	121,000
Total minimum payments	$1,248,000

Rent expense for office space for the years ended December 31, 2009 and 2008 was $684,000 and $707,000, respectively.

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2009 and 2008 is as follows:

	2009	2008
Asset retirement obligation—beginning of period	$19,541,000	$17,361,000
Liabilities incurred	—	627,000
Liabilities settled	(1,824,000)	(1,292,000)
Accretion expense	1,720,000	1,395,000
Revisions in estimated liabilities	(71,000)	1,450,000
Asset retirement obligation—end of period	$19,366,000	$19,541,000

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 a 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 the Company's wells, the costs to ultimately retire the wells may vary significantly from previous estimates.

During the year 2009 the Company incurred a loss on settlement of asset retirement obligation in the amount of $2,038,000. This loss was the result of actual plugging costs on Prime Offshore properties exceeding the liability that had been originally estimated.

7. Contingent Liabilities

The Company, as managing general partner of the affiliated Partnerships, is responsible for all Partnership activities, including the drilling of development wells and the production and sale of oil and gas from productive wells. The Company also provides the administration, accounting and tax preparation work for the Partnerships, and is liable for all debts and liabilities of the affiliated Partnerships, to the extent that the assets of a given limited Partnership are not sufficient to satisfy its obligations. As of December 31, 2009, 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.

From time to time, the Company is party to certain legal actions 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.

8. Stock Options and Other Compensation

In May 1989, non-statutory stock options were granted by the Company to four key executive officers for the purchase of shares of common stock. At December 31, 2009 and 2008, options on 767,500 shares were outstanding and exercisable at prices ranging from $1.00 to $1.25. According to their terms, the options have no expiration date.

9. Income Taxes

The components of the provision (benefit) for income taxes for the years ended December 31, 2009 and 2008 are as follows:

	2009	2008
Current:		
Federal	$ (3,484,000)	$ 754,000
State	351,000	691,000
Total current	$ (3,133,000)	$ 1,445,000
Deferred:		
Federal	(9,016,000)	(1,158,000)
State	(156,000)	(228,000)
Total deferred	$ (9,172,000)	$(1,386,000)
Total income tax provision (benefit)	$(12,305,000)	$ 59,000

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

	December 31, 2009	December 31, 2008
Current assets:		
Accrued liabilities	$ 414,000	$ 415,000
Allowance for doubtful accounts	303,000	108,000
Derivative contracts	121,000	139,000
Total current deferred income tax assets	$ 838,000	$ 662,000
Current liabilities:		
Derivative contracts	$ —	$ 632,000
Net current deferred tax asset	$ 838,000	$ 30,000
Non-current assets:		
Alternative minimum tax credits	$ 5,294,000	$ 7,946,000
Net operating loss carry-forwards	3,698,000	161,000
Percentage depletion carry-forwards	1,101,000	1,101,000
Total non-current assets	$10,093,000	$ 9,208,000
Non-current liabilities:		
Basis differences relating to partnerships	$ 491,000	$ 1,774,000
Proved oil and gas properties	26,237,000	33,045,000
Derivative contracts	—	77,000
Total non-current liabilities	$26,728,000	$34,896,000
Net non-current deferred income tax liabilities	$16,635,000	$25,688,000

The total provision for income taxes for the years ended December 31, 2009 and 2008 varies from the federal statutory tax rate as a result of the following:

	December 31, 2009	December 31, 2008
Expected tax expense (benefit)	$(12,235,000)	$ 203,000
State income tax, net of federal benefit	195,000	309,000
Percentage depletion	—	(639,000)
Executive compensation	—	186,000
Other, net	(265,000)	—
Tax expense	$(12,305,000)	$ 59,000

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 "Proved oil and gas properties", while basis differences relating to the managed partnerships are reflected under "Basis differences relating to managed partnerships".

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.

The Company has not recorded any provision for uncertain tax positions.

The Company files income tax returns in the U.S. federal jurisdiction and various states. During 2008, the Internal Revenue Service completed its review of the Company's Federal income tax returns for the years ended 2004 through 2006, and of a refund claim based on carrying a 2006 net operating loss to 2005. No changes were made to the amounts reported in any of the periods examined, or to the refund claimed.

10. Segment Information and Major Customers

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

The Company sells its oil and gas production to a number of purchasers. Listed below are the percent of the Company's total oil and gas sales made to each of the customers whose purchases represented more than 10% of the Company's oil and gas sales in the year 2009.

Oil Purchasers:		Gas Purchasers:	
Texon Distributing L.P.	20%	Unimark LLC	13%
Plains All American Inc.	59%	Cokinos Energy Corporation	30%
		Atlas Pipeline Mid-Continent WestOK, LLC	17%

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

11. Financial Instruments

Fair Value measurements:

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value. The fair values of the Company's interest rate swaps, natural gas and crude oil price collars and swaps are designated as Level 3. The following fair value hierarchy table presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2009 and 2008:

	Quoted Prices in Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2009
Assets				
Commodity derivative contracts	—	—	$ 879,000	$ 879,000
Total assets	—	—	$ 879,000	$ 879,000
Liabilities				
Commodity derivative contracts	—	—	$(4,845,000)	$(4,845,000)
Interest rate derivative contracts	—	—	$ (335,000)	$ (335,000)
Total liability	—	—	$(5,180,000)	$(5,180,000)

	Quoted Prices in Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2008
Assets				
Commodity derivative contracts	—	—	$ 2,111,000	$ 2,111,000
Total assets	—	—	$ 2,111,000	$ 2,111,000
Liabilities				
Interest rate derivative contracts	—	—	$ (533,000)	$ (533,000)
Total liability	—	—	$ (533,000)	$ (533,000)

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as level 3 in the fair value hierarchy for the years ended December 31, 2009 and 2008.

	Year Ended December 31,	
	2009	2008
Net assets (liabilities) at beginning of period	$ 1,578,000	$ (3,618,000)
Total realized and unrealized losses:		
Included in earnings (a)	399,000	(5,446,000)
Included in other comprehensive income	(2,312,000)	10,927,000
Purchases, sales, issuances and settlements, net	(3,966,000)	(285,000)
Net assets (liabilities) at end of period	$(4,301,000)	$ 1,578,000

(a) Amounts reported in net income are classified as oil and gas sales for commodity derivative instruments reported as cash flow hedges prior to July 1, 2009 and as a reduction to interest expense for interest rate swap instruments. Derivative instruments for periods after July 1, 2009 are reported in oil and gas sales as realized gain/loss and on a separately reported line item captioned unrealized gain/loss on derivative instruments.

Assuming no change in interest prices, after December 31, 2009, the Company would expect to reclassify to the statement of operations, over the next twelve months, $214,000 in after-tax loss associated with interest rate swaps. This reclassification represents the net short-term payable associated with open swaps currently not reflected in earnings at December 31, 2009 related to anticipated interest expense.

Derivative Instruments:

In March 2008, the FASB issued guidance and amended the disclosure requirements for derivative and hedging activities. Entities are now required to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity.

The Company is exposed to commodity price and interest rate risk, and management considers periodically the Company's exposure to cash flow variability resulting from the commodity price changes and interest rate fluctuations. Futures, swaps and options are used to manage the Company's exposure to commodity price risk inherent in the Company's oil and gas production operations. The Company does not apply hedge accounting to any of its commodity based derivatives. The application of hedge accounting for commodities was discontinued for periods after July 1, 2009. As a result, both realized and unrealized gains and losses associated with derivative instruments are recognized in earnings. If the derivatives previously reported as cash flow hedges had losses or gains not yet settled, these items would be reported in accumulated other comprehensive income until settlement occurs and reclassified appropriately from accumulated other comprehensive income into the statement of operations.

Interest rate swaps derivatives continue to be treated as cash-flow hedges and are used to fix or float interest rates on existing debt. The value of these interest rate swaps at December 31, 2009 is located in accumulated other comprehensive income and settlement of the swaps is recorded within interest expense.

Effect of derivative instruments on the consolidated balance sheet:

	Balance Sheet Location	Fair Value December 31, 2009	Fair Value December 31, 2008
Asset Derivatives:			
Derivatives designated as hedging instruments:			
Crude oil commodity contracts	Current derivative contracts	—	$1,755,000
Crude oil commodity contracts	Other assets	—	356,000
Total		$ —	$2,111,000
Derivatives not designated as hedging instruments:			
Natural gas commodity contracts	Current derivative contracts	657,000	—
Natural gas commodity contracts	Other assets	222,000	—
Total		$ 879,000	$ —
Liability Derivatives:			
Derivatives designated as hedging instruments:			
Interest rate swap derivatives	Derivative liability short term	$ (335,000)	$ (387,000)
Interest rate swap derivatives	Derivative liability long term	—	(146,000)
Total		$ (335,000)	$ (533,000)
Derivatives not designated as hedging instruments:			
Crude oil commodity contracts	Derivative liability short term	(1,953,000)	—
Crude oil commodity contracts	Derivative liability long term	(2,892,000)	—
Total		$(4,845,000)	$ —
Total derivative instruments		$(4,301,000)	$1,578,000

Effect of derivative instruments on the consolidated statement of operations:

	Location of gain/loss reclassified from OCI into income	Amount of gain/loss reclassified from accumulated OCI into income	
		2009	2008
Derivatives designated as cash-flow hedges			
Interest rate swap derivatives	Interest expense	$ (881,000)	$ 387,000
Crude oil commodity contracts	Oil and gas sales	1,519,000	(7,445,000)
		$ 638,000	$(7,058,000)

	Location of gain/loss recognized in income	Amount of gain/loss recognized in income	
		2009	2008
Derivatives not designated as cash-flow hedge instruments			
Natural gas commodity contracts	Loss on derivative instruments	$ 879,000	$ —
Crude oil commodity contracts	Loss on derivative instruments	$(4,845,000)	—
Crude oil commodity contracts	Oil and gas sales	(14,000)	
		$(3,980,000)	$ —

12. Related Party Transactions

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 $152,000 during 2009 and $481,000 during 2008.

Treasury stock purchases in any reported period may include shares from a related party. There were no related party treasury stock purchases during the year ending December 31, 2009. Purchases from related parties in 2008 included 70,000 shares purchased for a total consideration of $3,500,000.

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. Included at December 31, 2008 in due from related parties is an amount of $574,000 by two members of the Company's Board of Director for their participation in a project with the Company's offshore subsidiary.

Payables owed to related parties primarily represent 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. Also included in due to related parties is the amount of accrued interest owed to the related party, a company controlled by a director of the Company, with whom the Company's offshore subsidiary entered into a credit agreement. The agreement provides for a loan of $20 million at a rate of 10% per annum and is secured by a second lien position of all the assets of the offshore subsidiary. Included at each of December 31, 2009 and 2008 was $170,000 of accrued interest on the related party loan.

13. Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents include $5,497,000 and $8,027,000 at December 31, 2009 and 2008, respectively, of cash primarily pertaining to oil and gas revenue payments. There were corresponding accounts payable recorded at December 31, 2009 and 2008 for these liabilities. Both the restricted cash and the accounts payable are classified as current on the accompanying balance sheet.

14. Salary Deferral Plan

The Company maintains a salary deferral plan (the "Plan") in accordance with Internal Revenue Code Section 401(k), as amended. The Plan provides for discretionary and matching contributions, the latter of which approximated $416,000 and $438,000 in 2009 and 2008, respectively.

15. Earnings (Loss) per Share

Basic earnings (loss) per share are computed by dividing earnings (loss) 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 in gain periods. The following reconciles amounts reported in the financial statements:

	Year ended December 31, 2009		
	Net Income	Number of Shares	Per share Amount
Net loss per common share	$(23,679,000)	3,038,313	$(7.79)
Effect of dilutive securities:			
Options (a)	—	—	
Diluted net loss per common share	$(23,679,000)	3,038,313	$(7.79)

	Year ended December 31, 2008		
	Net Income	Number of Shares	Per share Amount
Net income per common share	$ 541,000	3,062,159	$ 0.18
Effect of dilutive securities:			
Options	—	753,754	
Diluted net income per common share	$ 541,000	3,815,913	$ 0.14

(a) The dilutive effect of 767,500 outstanding stock purchase options is not considered for the year ended December 31, 2009, due to the loss incurred for such period.

16. Shareholder's Equity

The Company has in place a stock repurchase program whereby it may purchase outstanding shares of its common stock from time-to-time, in open market transactions or negotiated sales. The Company uses the cost method to account for its treasury share purchases. Effective July 1, 2009, pursuant to a vote of the shareholders amending the Articles of Incorporation, the authorized shares of common stock were reduced from 10,000,000 to 4,000,000, and the class of Preferred Stock of the Company, no shares of which had been issued, was eliminated. The amendment was filed with the Secretary of State in Delaware. The cost of the cancelled shares was determined by use of the first-in, first-out valuation method. The cost of the reacquired shares was $11,936,000. The cost was allocated between the par value ($0.10) of the shares cancelled; the excess of cost over the par value to paid in capital based upon the average per share amount of paid in capital ($1.43) for all shares from the original issuance; and the excess was charged to retained earnings.

PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES
Years Ended December 31, 2009 and 2008

(Unaudited)

	2009	2008
Developed oil and gas properties	$441,035,000	$426,190,000
Undeveloped oil and gas properties	1,322,000	3,393,000
	442,357,000	429,583,000
Accumulated depreciation, depletion and valuation allowance	268,514,000	217,434,000
Net capitalized costs	$173,843,000	$212,149,000

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES
Years Ended December 31, 2009 and 2008
(Unaudited)

	2009	2008
Acquisition of Properties Developed	$ —	$ —
Undeveloped	$ —	$ —
Exploration Costs	$ 136,000	$ 649,000
Development Costs	$17,474,000	$53,718,000

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES
Years Ended December 31, 2009 and 2008
(Unaudited)

	2009	2008
Future cash inflows	$ 549,104,000	$ 505,316,000
Future production and development costs	(326,040,000)	(297,414,000)
Future income tax expenses	(38,199,000)	(31,259,000)
Future net cash flows	184,835,000	176,643,000
10% annual discount for estimated timing of cash flow	(82,093,000)	(60,109,000)
Standardized measure of discounted future net cash flows	$ 102,742,000	$ 116,534,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION AND SUBSIDIARIES

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN RELATING TO PROVED OIL AND GAS RESERVES Years Ended December 31, 2009 and 2008

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2009 and 2008:

For Year Ended December 31,	2009	2008
Sales of oil and gas produced, net of production costs	$ 35,853,000	$ (92,393,000)
Net changes in prices and production costs	(143,108,000)	(129,629,000)
Extensions, discoveries and improved recovery	75,028,000	45,879,000
Revisions of previous quantity estimates	(32,725,000)	(34,889,000)
Reserves purchased, net of development costs	—	—
Net change in development costs	45,122,000	27,975,000
Reserves sold	—	—
Accretion of discount	11,653,000	28,747,000
Net change in income taxes	(6,940,000)	44,372,000
Changes in production rates (timing) and other	1,325,000	1,012,000
Net change	(13,792,000)	(108,926,000)
Standardized measure of discounted future net cash flow:		
Beginning of year	116,534,000	225,460,000
End of year	$ 102,742,000	$ 116,534,000

See accompanying notes to supplementary information.

RESERVE QUANTITY INFORMATION
Years Ended December 31, 2009 and 2008
(Unaudited)

	2009		2008	
	Oil (bbls.)	Gas (Mcf)	Oil (bbls.)	Gas (Mcf)
Proved developed and undeveloped reserves:				
Beginning of year	5,317,000	55,338,000	6,592,000	61,412,000
Extensions, discoveries and improved recovery	2,136,000	10,198,000	2,048,000	6,409,000
Revisions of previous estimates	(726,000)	(12,994,000)	(2,665,000)	(3,584,000)
Purchases	—	—	—	—
Reserves sold	—	—	—	—
Production	(640,000)	(7,129,000)	(658,000)	(8,899,000)
End of year	6,087,000	45,413,000	5,317,000	55,338,000
Proved developed reserves	4,476,000	38,389,000	5,317,000	54,140,000

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES
Years Ended December 31, 2009 and 2008
(Unaudited)

	2009	2008
Revenue:		
Oil and gas sales	$69,343,000	$135,036,000
Costs and expenses:		
Lease operating expense	33,490,000	42,643,000
Exploration costs	136,000	649,000
Depreciation and Depletion	48,782,000	69,711,000
Income tax expense (benefit)	(4,597,000)	4,995,000
	77,811,000	117,998,000
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ (8,468,000)	$ 17,038,000

See accompanying notes to supplementary information.

PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO SUPPLEMENTARY INFORMATION
(Unaudited)

1. Presentation of Reserve Disclosure Information

Reserve disclosure information is presented in accordance with generally accepted accounting principles. The Company's reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of the Company's reserves.

2. Determination of Proved Reserves

The estimates of the Company's proved reserves were determined by an independent petroleum engineer in accordance with generally accepted accounting principles. 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 generally accepted accounting principles. 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 generally accepted accounting principles.

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 applicable guidance) 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.

5. Changes in Reserves

The 2009 and 2008 extensions and discoveries reflect the successful drilling activity in our West Texas area.

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Corporate Information

Auditors

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

Counsel

James F. Gilbert
Dallas, Texas

Commercial Bankers

Amegy Bank N.A.

BBVA Compass

BNP Paribas

JPMorgan Chase Bank, N.A.

Transfer Agent

Computershare Trust Company, N.A.
250 Royall Street
Canton, Massachusetts 02021

Annual Meeting

May 20, 2010, at 9:00 a.m. EDT
at the offices of the Company
One Landmark Square, 11th Floor
Stamford, Connecticut 06901

NASDAQ Symbol

PNRG

Executive Offices

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Stamford, Connecticut 06901
(203) 358-5700

Operating Offices

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Houston, Texas

Prime Operating Company
Houston, Texas
Midland, Texas
Oklahoma City, Oklahoma
Charleston, West Virginia

Field Offices:
Kingfisher, Oklahoma
Garvin, Oklahoma
Carrizo Springs, Texas
Midland, Texas
Orma, West Virginia

PrimeEnergy Management Corporation
Stamford, Connecticut

Eastern Oil Well Service Company
Houston, Texas
Midland, Texas
Oklahoma City, Oklahoma
Charleston, West Virginia

Southwest Oilfield Construction Company
Kingfisher, Oklahoma

10-K Information

The Company's 2009 Annual Report on Form 10-K, as filed with the Securities and Exchange Commission (except for exhibits) is included herein. Exhibits to the Form 10-K, which are indexed therein, are available upon request and the payment of a reproduction charge of fifteen cents per page by writing to:

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One Landmark Square
Stamford, CT 06901
Attn: Investor Relations

Officers

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

James F. Gilbert
Secretary

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

Lynne Pizor
Controller and Chief Accounting Officer

Directors

Beverly A. Cummings
PrimeEnergy Corporation

Charles E. Drimal, Jr.
PrimeEnergy Corporation

Matthias Eckenstein
Architect and Developer
Basel, Switzerland

H. Gifford Fong
Investment Technology Consultant
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Private Investor
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PrimeEnergy Corporation
2009 Annual Report