AMERICAN NATIONAL INSURANCE CO /TX/
Form 4
May 03, 2016

FORM 4

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

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL

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(Print or Type Responses)

1. Name and Address of Reporting Person *
MOODY ROBERT JR
(Last) (First) (Middle)
ONE MOODY PLAZA
(Street)
GALVESTON, TX 77550
(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
AMERICAN NATIONAL INSURANCE CO /TX/ [ANAT]

3. Date of Earliest Transaction (Month/Day/Year)
05/02/2016

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer
(Check all applicable)
_____ Director _____ 10% Owner
_____ Officer (give title below) __X__ Other (specify below)
Advisory Director

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security	2. Conversion or Exercise	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any	4. Transaction Code	5. Number of Derivative	6. Date Exercisable and Expiration Date (Month/Day/Year)	7. Title and Amount of Underlying Securities (Instr. 3 and 4)

(Instr. 3)	Price of Derivative Security		(Month/Day/Year)	(Instr. 8)		Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)					
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares
Restricted Stock Units	(1)	05/02/2016		A		750		05/02/2017 (2)	05/02/2017 (2)	Common Stock	750

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
MOODY ROBERT JR ONE MOODY PLAZA GALVESTON, TX 77550				Advisory Director

Signatures

Robert L. Moody, Jr., by J. Mark Flippin as Attorney-in-Fact	05/03/2016
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Each restricted stock unit represents a contingent right to receive, upon vesting, one share of Issuer's common stock or, at the election of the reporting person, cash in an amount equal to the closing price of such stock on the date of vesting.

(2) These restricted stock units vest on May 2, 2017, or upon the reporting person's earlier retirement, death or disability.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. tx144742_4">UNRESOLVED STAFF COMMENTS 18 Item 2. PROPERTIES 18 Item 3. LEGAL PROCEEDINGS 23 Item 4. RESERVED 23

PART II

Item 5.

MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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PrimeEnergy Corporation

FORM 10-K ANNUAL REPORT

For the Fiscal Year Ended

December 31, 2010

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 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, 2010, the Company had net capitalized costs related to oil and gas properties of $143 million, including $698 thousand of unproved properties. Total expenditures for the acquisition, exploration and development of the Company s properties during 2010 were $14 million of which $91,000 related to exploration costs expensed during 2010. Proved reserves as of December 31, 2010, were 101 BCFe of gas which consisted of 73% proved developed reserves and 27% proved undeveloped reserves.

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Significant 2010 activity

During 2010, the Company participated in drilling a total of 47 gross (19.96 net) wells, all of which were successful completions. In July 2010 the Company entered into a joint development agreement with a Korean consortium to develop oil properties in West Texas. This agreement provides for the drilling of 47 wells and a $5 million carry of the Company s drilling costs by the joint venture partners. As of March 31st, 42 wells have been drilled, 26 are currently producing, and 16 are in various stages of completion. The Company believes the relationship with the joint venture partners may have a significant impact on the growth of the Company activities.

In April 2010, the Deepwater Horizon drilling rig, which was engaged in deepwater Gulf of Mexico drilling operations for another operator, sank after an explosion and fire. In response to this event and the resulting oil spill, the Bureau of Ocean Energy Management, Regulation and Enforcement of the U.S. Department of the Interior (BOEMRE), formerly known as the Minerals Management Service (MMS), announced a series of moratoria which directed oil and gas lessees and operators to cease drilling new deepwater (depths greater than 500 feet) wells on the Outer Continental Shelf (OCS), and put oil and gas lessees and operators on notice that, with certain exceptions, the BOEMRE would not consider drilling permits for deepwater wells and related activities. In addition, the BOEMRE issued new regulations in 2010 requiring additional information, documentation and analysis for all new wells on the OCS. While the moratoria have been formally lifted, the effect of these new regulations was to significantly slow down issuance of permits for shallow wells. This event and its aftermath have created uncertainty with regard to offshore exploration and production activity, including future regulatory requirements, operational delays and cost increases. This may create some opportunities for acquisitions as other companies leave the Gulf of Mexico due to the perceived tightening of the regulatory environment. Currently none of our operations are conducted in deep water.

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.

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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 1,599 oil and gas wells, 364 through the Houston office, 326 through the Midland office, 411 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 2,535.

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

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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 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 ships 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

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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 the BOEMRE and are required to comply with the regulations and orders promulgated by BOEMRE under OCSLA. Among other things, the Company is required to obtain prior BOEMRE approval for any exploration plans it pursues and the development and production plans for these leases. BOEMRE 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, BOEMRE could require the Company to suspend or terminate operations on a federal lease.

BOEMRE 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 BOEMRE 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.

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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.	19%
Plains All American Inc.	62%
Gas Purchasers:	
Unimark LLC	15%
Cokinos Energy Corporation	16%
Atlas Pipeline WestTex, LLC	28%

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

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Environmental Matters

Various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), the Federal Water Pollution Control Act of 1972, as amended (the Clean Water Act), and the Federal Clean Air Act, as amended (the Clean Air Act), affect 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

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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,

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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). BOEMRE permit approvals will be conditioned on collection and removal of debris resulting from activities related to exploration, development and production of offshore leases. BOEMRE 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

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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 BOEMRE 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 BOEMRE, 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 18, 2011, the Company had 229 full-time and 11 part-time employees, 18 of whom were employed by the Company at its principal offices in Stamford, Connecticut, 39 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 183 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

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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

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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.

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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 maintain insurance coverage against certain, but not all, hazards that could arise from our operations both onshore and offshore. Such insurance is believed to be reasonable for the hazards and risks faced by us.

As of December 31, 2010, we maintain for offshore operations total excess liability insurance with limits of $35 million per occurrence and in the aggregate covering certain general liability and certain sudden and accidental environmental risks with a deductible of $10,000 per occurrence, subject to all terms, restrictions and sub-limits of the policies. We also maintain for onshore operations total excess liability insurance with limits of $20 million per occurrence and in the aggregate covering certain general liability and certain sudden and accidental environmental risks with a deductible of $10,000 per occurrence, subject to all terms, restrictions and sub-limits of the policies. We maintain general liability insurance limits of $1 million per occurrence and $2 million in the aggregate for both our onshore as well as our offshore operations.

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We have several policies that cover environmental risks. We have environmental coverage under the per occurrence and aggregate limits of our general and umbrella liability policies (for a twelve-month term). These policies provide third-party surface cleanup, bodily injury and property damage coverage, and defense costs when a pollution event is sudden and accidental and is discovered within thirty days of commencement and reported to the insurance company within ninety days of discovery. This is standard coverage in oil and gas insurance policies. Additionally, offshore operations maintain additional coverage with an operators extra expense (control of well) policy (for a twelve-month term) which covers cleanup, third-party bodily injury and property damage, and defense costs when a well gets out of control above the surface of the ground or water bottom. This coverage falls under a Combined Single Limit of $35,000,000. PrimeEnergy s Combined Single Limit is subject to an annual aggregate of $17,500,000 for the interests insured in the event a loss under the policy is caused by a Named Windstorm.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Those risks include pollution liability in excess of limits sufficient to meet the legal financial responsibility requirement of the BOEMRE as prescribed under the Federal Oil Pollution Act and individual state legal financial responsibility requirements.

Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our customers and contractors. However, customers and contractors who provide contractual indemnification protection may not in all cases maintain adequate insurance to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a customer to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may not be able to maintain adequate insurance in the future at rates we consider reasonable.

With regard to our offshore operations, generally, indemnities and insurance limits for each contract are negotiated with each of our contractors. Our contracts generally follow the industry standard of providing mutual hold harmless and indemnity agreements, which results in each party being liable or responsible for all claims related to its employees and its contractors, as well as any damage to its and its contractor s property. Currently, substantially all of our contracts contain mutual hold harmless and indemnity provisions.

From time to time, a small number of our contractors have requested contractual provisions that require us to respond to third-party claims. In some of these instances we have accepted the risk with the understanding that it would be covered under our current coverage. We evaluate these risk-transferring negotiations cautiously, and we feel that we have adequately mitigated this risk through existing coverage or acquiring supplemental coverage when appropriate.

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.

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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

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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, 2010.

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil					2	1.50
Gas						
Dry						
Development:						
Oil	47	19.96	13	11.74	69	40.18
Gas						
Dry						
Total:						
Oil	47	19.96	13	11.74	71	41.68
Gas						
Dry						
	47	19.96	13	11.74	71	41.68

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Oil and Gas Production

As of December 31, 2010, 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	968	377
Gas Wells	1,153	509
Producing Acres	318,161	107,829

(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, 2010. 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.

	2010	2009	2008
Oil (barrels)	627,000	640,000	658,000
Gas (Mcf)	5,939,000	7,129,000	8,899,000

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, 2010.

	2010	2009	2008
Average sales price per barrel	$ 75.11	59.16	84.43
Average sales price Per Mcf	$ 6.43	4.42	8.93
Average production costs per net equivalent barrel (1)	$ 21.64	18.32	19.92

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

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

	2010	2009	2008
Oil Price	$ 75.81	56.80	95.74
Gas Price	$ 5.75	4.42	9.09

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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, 2010. 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	11,520	9,600				
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	4,328	1,586	640	2		
West Virginia						
Wyoming					140	35
TOTAL	20,024	13,081	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, 2010. The professional qualifications of the technical persons primarily responsible for overseeing the preparation of the reserves estimates can be found in Exhibit 99.1, the Ryder Scott Company, L.P. Report on Registrant s Reserves Estimates. In matters related to the preparation of our reserve estimates, our district managers report to the Houston Central manager, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides oversight for the annual preparation of reserve estimates of 100% of our year-end reserves by our independent third party engineers, Ryder Scott Company, L.P. The members of our district and central groups consist of degreed engineers, geologists and geophysicists and technicians with between approximately ten and thirty-five years of industry experience, and between three and twenty years managing our reserves. Our Houston Central manager, the technical person primarily responsible for overseeing the preparation of reserves estimates, has over twenty-five years of experience, holds a Bachelor of Science degree in Natural Gas Engineering and is a member of the Society of Petroleum Engineers and American Association of Petroleum Geologists. See Part II, Item 8., Financial Statements and Supplementary Data , for additional discussions regarding proved reserves and their related cash flows.

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)**
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
2010	5,233,000	41,946,000	2,652,000	11,400,000	7,885,000	53,346,000

Our proved undeveloped reserves as of December 31, 2008 consisted of one prospect in the Gulf of Mexico awaiting completion. During 2009 this prospect was completed under a farm out agreement whereby the

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Company s share of completion costs were carried by the outside working interest partners, therefore no capital expenditure by the Company was required. Additions to proved undeveloped reserves during 2009 included fifty-four in-fill drilling locations in our West Texas drilling program. During 2010 we drilled 43 West Texas wells and acquired additional leasehold in the area. Proved undeveloped reserves as of December 31, 2010 included 75 in-fill drilling locations in our West Texas drilling program. As of March 31, 2011 we have drilled 7 of those wells. The Company has no proved undeveloped reserves that remain undeveloped for five years or more.

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, 2010, 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
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
2010	$ 282,004,000	168,095,000	100,934,000	26,696,000	382,938,000	194,791,000	48,307,000	146,484,000

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 (GAAP), 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 PV 10 of future income taxes represents the sole reconciling item between this non-GAAP PV 10 Value versus the GAAP measure presented in the standardized measure of discounted cash flow. A reconciliation of these values is presented in the last three columns of the table above. 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 basic sediment and water) 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 2010 was a low of $3.17 and a high of $7.38 and the average was $4.37. The range during the first quarter of 2011 has been from $3.76 to $4.73 with an average of $4.24. The recent futures market prices have traded above $4.23 per MMBTU.

The range of NYMEX oil prices per barrel during the year 2010 was a low of $68.01 and a high of $91.51 and the average was $79.60. The range during the first quarter of 2011 has been from $84.32 to $106.72, with an average of $94.62. The recent futures market prices have fluctuated around $107.00.

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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, 2011, 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, 2010.

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Offshore	Other	Total
Proved Reserves at Year End (Mmcfe)							
Developed	7,624	6,275	15,549	40,041	2,512	1,343	73,344
Undeveloped				26,962	352		27,314
Total	7,624	6,275	15,549	67,003	2,864	1,343	100,658
Average Daily Production (Mmcfe per day)	2.4	3.5	5.8	11.2	3.1	.5	26.5
Gross Wells	715	371	768	473	16	141	2,484
Net Wells	375	136	253	150	7	19	940
Gross Operated Wells	498	289	411	326	14	61	1,599

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, 2010, we had 715 wells (375 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 2010 was 2.4 Mmcfe. 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, 2010, we had 7.6 Bcfe of proved reserves (substantially all natural gas) in the Appalachian region, constituting 8% of our total proved reserves. This region is managed from our office in Charleston, West Virginia. As of March 31, 2011 the Appalachian region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

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 371 wells (136 net) in the Gulf Coast region as of December 31, 2010, of which 289 wells are operated by us. Average daily production in 2010 was 3.5 Mmcfe. At December 31, 2010, we had 6.3 Bcfe of proved reserves (69% natural gas) in the Gulf Coast region, which represented 6% of our total proved reserves. As of March 31, 2011 the Gulf Coast region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

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Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. As of December 31, 2010, we had 768 wells (253 net) in the Mid-Continent area, of which 411 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 2010 was 5.8 Mmcfe. At December 31, 2010, we had 15.5 Bcfe of proved reserves (61% natural gas) in the Mid-Continent area, or 15% of our total proved reserves. This region is managed from our office in Oklahoma City. As of March 31, 2011 the Mid-Continent region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas and New Mexico. As of December 31, 2010, we had 473 wells (150 net) in the West Texas area, of which 326 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 2010 was 11.2 Mmcfe. At December 31, 2010, we had 40 Bcfe of proved reserves (42% natural gas) in the West Texas area, or 67% of our total proved reserves. This region is managed from our office in Midland, Texas. As of March 31, 2011 the West Texas region has 1 well in the process of being drilled and 16 awaiting completion, no waterfloods in the process of being installed and no other related activities of material importance.

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 16 wells (7 net) in the Offshore Gulf of Mexico region as of December 31, 2010, of which 14 wells are operated by us. Average daily production in 2010 was 3.1 Mmcfe. At December 31, 2010, we had 2.5 Bcfe of proved reserves (substantially all natural gas) in the Offshore Gulf of Mexico region, which represented 3% of our total proved reserves. As of March 31, 2011 the Offshore Gulf of Mexico region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

Acreage subject to expiration in the next three years

	2011		2012		2013	
State	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
GULF OF MEXICO	11,520	9,600				
OKLAHOMA						
TEXAS						
NEW MEXICO						
WEST VIRGINIA						
COLORADO						
TOTAL	11,520	9,600				

Item 3. LEGAL PROCEEDINGS.

Not applicable

Item 4. RESERVED.

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PART II

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

The Company s Common Stock is traded in the NASDAQ Stock Market, trading symbol PNRG . The high and low bid quotations for each quarterly period during the two years ended December 31, 2010, were as follows:

2010	High	Low	2009	High	Low
First Quarter	$ 37.12	$ 24.22	First Quarter	$ 55.97	$ 24.46
Second Quarter	$ 29.00	$ 15.98	Second Quarter	$ 53.22	$ 32.69
Third Quarter	$ 23.40	$ 17.71	Third Quarter	$ 36.74	$ 23.58
Fourth Quarter	$ 22.14	$ 17.68	Fourth Quarter	$ 38.74	$ 27.02

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, 2011, was 656.

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. The Board of Directors of the Company approved an additional 300,000 shares of the Company s stock to be included in the stock repurchase program effective May 20, 2010. A total of 3,000,000 shares have been authorized, to date, under this program. Through December 31, 2010, a total of 2,744,403 shares has been repurchased under this program for $37,553,268 at an average price of $13.68 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.

2010 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	2,000	$ 35.00	183,641
February	2,000	26.89	181,641
March	1,700	26.40	179,941
April			179,941
May	137,433	12.06	342,508
June	6,278	19.22	336,230
July	13,325	20.99	322,905
August	2,885	19.10	320,020
September	4,547	19.45	315,473
October	4,876	18.77	310,597

November	2,000	19.04	308,597
December	53,000	18.48	255,597
Total/Average/Remainder	230,044	$ 15.12	

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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.

Overview:

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. All of the Company s oil and gas properties and interests are located in the United States. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. We believe our balanced portfolio of assets and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities. Our primary sources of liquidity are cash generated from our operations and our credit facility.

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.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of increases in oil and gas prices above the maximum fixed amount specified in the derivative agreements and subjects us to the credit risk of the counterparties to such agreements. Since all of our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in gains and losses on mark-to-market derivative contracts in our consolidated income statement as changes occur in the NYMEX price indices.

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.

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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 provided by operating activities for the year ended December 31, 2010 was $62 million, compared to $34 million in the prior year. Additionally, under a joint development agreement, $5 million of the Company s capital expenditures were carried by the joint venture partners.

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 2010 was $3.8 million. The Company expects continue spending under these programs in 2011.

As of March 31, 2011, the Company maintains a credit facility totaling $250 million, with a borrowing base of $100 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. 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. As of March 31, 2011, the advances under this credit facility are $16 million due November 2014.

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

Results of Operations:

2010 as compared to 2009

The Company had net income of $2,753,000 in 2010 as compared to a net loss of $23,679,000 in 2009. The significant components of net income are discussed below.

Oil and gas sales were $85,263,000 in 2010 as compared to $69,343,000 in 2009. A chart summarizing oil and gas production and revenue is presented below.

	2010	2009	Increase (Decrease)
Barrels of Oil Produced	627,000	640,000	(13,000)
Average Price Received (rounded, including the impact of derivatives)	$ 75.11	$ 59.16	$ 15.95
Oil Revenue	$ 47,093,000	$ 37,860,000	$ 9,233,000
Mcf of Gas Produced	5,939,000	7,129,000	(1,190,000)
Average Price Received (rounded, including the impact of derivatives)	$ 6.43	$ 4.42	$ 2.01
Gas Revenue	$ 38,170,000	$ 31,483,000	$ 6,687,000
Total Oil & Gas Revenue	$ 85,263,000	$ 69,343,000	$ 15,920,000

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

	2010	2009	Increase (Decrease)
Oil Price	$ 75.81	$ 56.80	$ 19.01
Gas Price	$ 5.75	$ 4.42	$ 1.33

The decrease in oil production reflects the natural decline of existing properties offset by properties added during 2010 from our West Texas drilling program. The decrease in gas production is primarily due to the natural decline of the offshore properties.

Lease operating expense for 2010 increased by $1,494,000 or 4.46% compared to 2009. The offshore properties natural decline in gas production resulted in decreased costs, primarily in the area of marketing and transportation and workover expense. The decrease in lease operating expense on our offshore properties was offset by across-the-board increases on our onshore properties. The onshore properties increase was primarily due to increased production taxes related to higher commodity prices coupled with costs from the additional wells drilled in our West Texas region.

General and administrative expense increased $1,606,000 in 2010 or 13.54% as compared to 2009 primarily due to increased personnel costs. The largest component of these personnel costs was salaries, however, engineering consultants, rent and employee related taxes and insurance also contributed to the increase.

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Field service income for 2010 increased 36.05% to $22,621,000 in 2010 as compared to $16,627,000 in 2009. The most significant factor contributing to this increase was additional gas transportation revenue of approximately $4.9 million from our offshore properties recorded during the fourth quarter of 2010. In 2010 it was determined that we could recover a portion of the cost of our pipelines and we filed for and received payment on current as well as past recoveries. There are no expenses associated with this increase in gas transportation revenue. Water transport income contributed approximately $600 thousand towards the increase as a result of adding additional transport trucks and placing a new salt water disposal well into service in our south Texas area. Service rig income was the final contributor with a net increase of approximately $500 thousand. Service rig income in our west Texas area increased but was offset by a decrease in our south Texas area primarily as a result of the transfer of a rig from south Texas to west Texas.

Depreciation, depletion, amortization and accretion on discounted liabilities expense decreased to $45,688,000 in 2010 from $55,741,000 in 2009 or 18.04%. This decrease is primarily related to the decrease in offshore production during 2010.

Interest expense decreased 9.81% to $6,650,000 in 2010 from $7,373,000 in 2009. This decrease is due to lower outstanding debt balances during the year offset by slightly higher average interest rates. The average interest rates paid on outstanding bank borrowings subject to interest during 2010 and 2009 were 6.09% and 5.59% respectively. As of December 31, 2010 and 2009, the total outstanding borrowings were $93,100,000 and $113,995,000, respectively.

A provision for income taxes of $1,002,000 was recorded for 2010 while a benefit from income taxes of $12,305,000 was recorded for 2009. The provision for income taxes varies from the federal statutory tax rate primarily due to percentage depletion. 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.

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.

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

Members of our management, including our chief executive officer and chief financial officer, have evaluated the effectiveness of our disclosure controls and procedures, as defined by paragraph (e) of Exchange Act Rules 13a-15 or 15d-15, as of December 31, 2010, the end of the period covered by this report. Based upon that evaluation, these officers concluded that our disclosure controls and procedures were effective as of December 31, 2010.

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, 2010. 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, 2010.

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 changes in our internal controls over financial reporting during the fourth fiscal quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.

None.

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company s Directors, nominees for Directors and executive officers is included in the Company s definitive proxy statement relating the Company s Annual Meeting of Stockholders to be held in May, 2011 which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2010, 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, 2011, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2010, 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, 2011, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2010, 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, 2011, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2010, 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, 2011, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2010, and which is incorporated herein by reference.

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PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.
The following documents are filed as part of this Report:

1. Financial statements (Index to 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-Q for the quarter ended June 30, 2010)
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)
10.22.5.9	Second Amended and Restated Credit Agreement dated July 30, 2010, by and among PrimeEnergy Corporation, the Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, and EOWS Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB) As Administrative Agent and Letter of Credit Issuer, BBVA Compass, As Sole Lead Arranger and Sole Bookrunner and The Lenders Signatory Hereto (BNP Paribas, JPMorgan Chase Bank, N.A. and Amegy Bank National Association) (Incorporated by reference to Exhibit 10.22.5.9 of PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2010)
10.22.5.10	Security Agreement (Pledge) effective July 30, 2010 by PrimeEnergy Corporation, in favor of Compass Bank (Incorporated by reference to Exhibit 10.22.5.10 of PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2010)

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10.22.5.11	Guaranty effective July 30, 2010, by PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, and EOWS Midland Company, in favor of Compass Bank (Incorporated by reference to Exhibit 10.22.5.11 of PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2010)
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) (Incorporated by reference to Exhibit 10.23.9 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2009)
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)
10.27.3	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)
10.27.3.2	Amended and Restated Loan Modification dated July 21, 2010, effective June 30, 2009, by and among Artic Management Corporation, Prime Offshore L.L.C and PrimeEnergy Corporation (Incorporated by reference to Exhibit 10.27.3.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2010)
10.27.3.3	Loan Modification dated January 10, 2011, effective January 3, 2010, by and among Artic Management Corporation, Prime Offshore L.L.C. and PrimeEnergy Corporation. (filed herewith)
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)
10.29	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).
99.1	Summary Reserve Report dated March 28, 2011, of Ryder Scott Company, L.P. (filed herewith).

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

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 7th day of April, 2011.

PrimeEnergy Corporation

By: /s/ CHARLES E. DRIMAL, JR.
Charles E. Drimal, Jr.
Chairman, Chief Executive Officer and 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 7th day of April, 2011.

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

/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, 2010 and 2009, and the related consolidated statements of operations, stockholders equity, comprehensive income, and cash flows for each of the years then ended. The Company s management is responsible for these financial statements. 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, 2010 and 2009, 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 7, 2011

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET, December 31, 2010 and 2009

	2010	2009
ASSETS:		
Current assets:		
Cash and cash equivalents	$ 32,792,000	$ 11,779,000
Restricted cash and cash equivalents	6,131,000	5,497,000
Accounts receivable, net	12,748,000	13,876,000
Due from related parties	140,000	30,000
Prepaid expenses	1,609,000	1,100,000
Derivative contracts	3,038,000	657,000
Inventory at cost	700,000	1,871,000
Deferred income taxes	595,000	838,000
Total current assets	57,753,000	35,648,000
Property and equipment, at cost:		
Proved oil and gas properties at cost	453,145,000	441,035,000
Unproved oil and gas properties at cost	698,000	1,322,000
Less: Accumulated depletion and depreciation	310,809,000	268,514,000
	143,034,000	173,843,000
Field and office equipment	19,499,000	19,462,000
Less: Accumulated depreciation	12,705,000	12,199,000
	6,794,000	7,263,000
Total net property and equipment	149,828,000	181,106,000
Other assets	579,000	764,000
Total assets	$ 208,160,000	$ 217,518,000
LIABILITIES AND STOCKHOLDERS EQUITY:		
Current liabilities:		
Current bank debt	$	$ 7,000,000
Accounts payable	34,376,000	21,291,000
Current portion of asset retirement and other long-term obligations	2,206,000	3,374,000
Derivative liability short term	3,048,000	2,288,000
Accrued liabilities	7,676,000	5,985,000
Due to related parties	350,000	450,000
Total current liabilities	47,656,000	40,388,000
Long-term bank debt	73,100,000	86,955,000
Indebtedness to related parties	20,000,000	20,000,000
Asset retirement obligations	15,285,000	16,862,000
Derivative liability long term	2,587,000	2,892,000
Deferred income taxes	16,445,000	16,635,000
Total liabilities	175,073,000	183,732,000

Stockholders equity PrimeEnergy:		
Common stock, $.10 par value; 2010 and 2009: Authorized: 4,000,000 shares, issued: 3,836,397 shares; outstanding 2010: 2,802,053 shares; outstanding 2009: 3,032,097 shares	383,000	383,000
Paid in capital	5,955,000	5,465,000
Retained earnings	46,478,000	43,725,000
Accumulated other comprehensive loss		(214,000)
	52,816,000	49,359,000
Treasury stock, at cost; 2010: 1,034,344 shares; 2009: 804,300 shares	(28,896,000)	(25,417,000)
Total stockholders equity PrimeEnergy	23,920,000	23,942,000
Non-controlling interest	9,167,000	9,844,000
Total stockholders equity	33,087,000	33,786,000
Total liabilities and stockholders equity	$ 208,160,000	$ 217,518,000

See accompanying notes to the consolidated financial statements.

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

for the years ended December 31, 2010 and 2009

	2010	2009
Revenue:		
Oil and gas sales	$ 85,263,000	$ 69,343,000
Field service income	22,621,000	16,627,000
Administrative overhead fees	8,707,000	7,972,000
Gain (loss) on derivative instruments	1,373,000	(3,966,000)
Other income	205,000	16,000
Total revenue	118,169,000	89,992,000
Costs and expenses:		
Lease operating expense	34,984,000	33,490,000
Field service expense	14,315,000	14,614,000
Depreciation, depletion, amortization and accretion on discounted liabilities	45,688,000	55,741,000
Loss on settlement of asset retirement obligation	37,000	2,038,000
General and administrative expense	13,464,000	11,858,000
Exploration costs	91,000	136,000
Total costs and expenses	108,579,000	117,877,000
Gain on sale and exchange of assets	1,725,000	236,000
Income (loss) from operations	11,315,000	(27,649,000)
Other income and expenses:		
Less: Interest expense	6,650,000	7,373,000
Add: Interest income	621,000	52,000
Income (loss) before provision for (benefit from) income taxes	5,286,000	(34,970,000)
Provision for (benefit from) income taxes	1,002,000	(12,305,000)
Net income (loss)	4,284,000	(22,665,000)
Less: Net income attributable to non-controlling interest	1,531,000	1,014,000
Net income (loss) attributable to PrimeEnergy	$ 2,753,000	$ (23,679,000)
Basic income (loss) per common share	$ .94	$ (7.79)
Diluted income (loss) per common share	$ .75	$ (7.79)

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

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS   EQUITY

for the years ended December 31, 2010 and 2009

	Common Stock								
	Shares	**Amount**	**Additional Paid In Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Treasury Stock**	**Total Stockholders Equity PrimeEnergy**	**Non-Controlling Interest**	**Total Stockholders Equity**
Balance at January 1, 2009	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
Purchase 230,044 shares of common stock						(3,479,000)	(3,479,000)		(3,479,000)
Net income				2,753,000			2,753,000	1,531,000	4,284,000
Other comprehensive income, net of taxes					214,000		214,000		214,000
Purchase of non-controlling interest			490,000				490,000	(840,000)	(350,000)
Distributions to non-controlling interest								(1,368,000)	(1,368,000)
Balance at December 31, 2010	3,836,937	$ 383,000	$ 5,955,000	$ 46,478,000	$	$ (28,896,000)	$ 23,920,000	$ 9,167,000	$ 33,087,000

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

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)

	Years Ended December 31, 2010	2009
Net income (loss)	$ 4,284,000	$ (22,665,000)
Other comprehensive income (loss), net of taxes:		
Reclassification adjustment for settled contracts, net of taxes of $125,000 and $230,000, respectively	222,000	408,000
Changes in fair value of hedge positions, net of taxes of $5,000 and $917,000, respectively	(8,000)	(1,631,000)
Total other comprehensive income (loss)	214,000	(1,223,000)
Comprehensive income (loss)	4,498,000	(23,888,000)
Less: Comprehensive income attributable to non-controlling interest	1,531,000	1,014,000
Comprehensive income (loss) attributable to PrimeEnergy	$ 2,967,000	$ (24,902,000)

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

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

for the years ended December 31, 2010 and 2009

	2010	2009
Cash flows from operating activities:		
Net income (loss)	$ 2,753,000	$ (23,679,000)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Non-controlling interest in earnings of partnerships	1,531,000	1,014,000
Depreciation, depletion, amortization and accretion on discounted liabilities	45,688,000	55,741,000
Gain on sale of properties	(1,725,000)	(236,000)
Unrealized (gain) loss on derivative instruments	(1,373,000)	3,966,000
Provision for deferred income taxes	(68,000)	(11,972,000)
Loss on settlement of asset retirement obligations	37,000	2,038,000
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	1,128,000	6,847,000
(Increase) decrease in due from related parties	(110,000)	649,000
(Increase) decrease in inventories	1,171,000	2,660,000
(Increase) decrease in prepaid expenses and other assets	(199,000)	454,000
Increase (decrease) in accounts payable	12,450,000	(2,697,000)
Increase (decrease) in accrued liabilities	1,028,000	(943,000)
Increase (decrease) in due to related parties	(100,000)	218,000
Net cash provided by operating activities	62,211,000	34,060,000
Cash flows from investing activities		
Capital expenditures, including exploration expense	(15,203,000)	(18,020,000)
Proceeds from sale of properties and equipment	1,909,000	236,000
Net cash used in investing activities	(13,294,000)	(17,784,000)
Cash flows from financing activities		
Purchase of stock for treasury	(3,479,000)	(413,000)
Purchase of non-controlling interests	(350,000)	(152,000)
Increase in long-term bank debt and other long-term obligations	72,170,000	43,100,000
Repayment of long-term bank debt and other long-term obligations	(94,877,000)	(57,147,000)
Distribution to non-controlling interest	(1,368,000)	(1,693,000)
Net cash used in financing activities	(27,904,000)	(16,305,000)
Net (decrease) in cash and cash equivalents	21,013,000	(29,000)
Cash and cash equivalents at the beginning of the year	11,779,000	11,808,000
Cash and cash equivalents at the end of the year	$ 32,792,000	$ 11,779,000
Supplemental disclosures:		
Income taxes paid during the year	$ 111,000	$ 463,000
Net income tax refunds received during the year	$ 2,268,000	$ 797,000
Interest paid during the year	$ 6,650,000	$ 7,373,000
Change in accrued expenses relating to property	$ (664,000)	$ 3,215,000

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

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 approximately 1,600 wells and owns non-operating interests in over 800 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 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.

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

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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.

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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 January 2010, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (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.

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 were 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. There was no impact on the Company s consolidated financial position, results of operations or cash flows as a result of the adoption of the required provisions.

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 $350,000 in 2010 and $152,000 in 2009.

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3. Additional Balance Sheet Information

Accounts receivable at December 31, 2010 and 2009 consisted of the following:

	December 31, 2010	December 31, 2009
Joint interest billing	$ 2,538,000	$ 2,411,000
Trade receivables	1,688,000	1,565,000
Oil and gas sales	8,139,000	7,774,000
Refundable prior years income taxes (note 9)		2,466,000
Other	724,000	83,000
	13,089,000	14,299,000
Less: Allowance for doubtful accounts	341,000	423,000
Total	$ 12,748,000	$ 13,876,000

Accounts payable at December 31, 2010 and 2009 consisted of the following:

	December 31, 2010	December 31, 2009
Trade	$ 3,421,000	$ 5,673,000
Royalty and other owners	10,395,000	9,920,000
Prepaid drilling deposits	12,871,000	189,000
Other	7,689,000	5,509,000
Total	$ 34,376,000	$ 21,291,000

Accrued liabilities at December 31, 2010 and 2009 consisted of the following:

	December 31, 2010	December 31, 2009
Compensation and related expenses	$ 2,010,000	$ 2,009,000
Property costs	3,282,000	2,137,000
Income tax	930,000	170,000
Other	1,454,000	1,669,000
	$ 7,676,000	$ 5,985,000

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 2010 or 2009.

5. Long-Term Debt

Bank Debt:

Effective December 15, 2010, the Company obtained a consent from its lenders to allow the Company the ability to repurchase up to an additional $1 million of the capital stock from the effective date through January 31, 2011. This amount is in addition to the amounts available for repurchases of shares under the original provisions of a loan agreement dated July 30, 2010. As part of the consent the lender s also agreed that as of the effective date the borrowing base is $100 million and the monthly reduction amount is $2 million with the first reduction of such borrowing base to begin on June 15, 2011.

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A first amendment to the credit facility with an effective date of September 30, 2010 was ratified in November 2010. This amendment further defined the limitations on loans or advances and investments made in the Company s limited partnerships.

The Company s long-term debt associated with the offshore credit facility with its principal lender was closed, and a final payment of $3,500,000 was made on July 28, 2010.

Effective July 30, 2010 the Company entered into a second amended and restated credit agreement between Compass Bank as agent and a syndicated group of lenders. The Company is party to a revolving line of credit and letter of credit facility of up to $250 million. This facility has a maturity date of July 30, 2014. The borrowing base as of the closing date was $100 million. 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 at their discretion the right to request the borrowing base be re-determined with a maximum of one such request each year. 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 facility. At any time if the sum of the outstanding borrowings and letter of credit exposures exceed the applicable portion of the borrowing base, PEC would be required to repay the excess amount within a prescribed period.

The credit facilities include terms and covenants that require the Company to maintain a minimum current ratio, total indebtedness to EBITDAX (earnings before depreciation, depletion, amortization, taxes, interest expense and exploration costs) ratio and interest coverage ratio, as defined, and restrictions are placed on the payment of dividends, the amount of treasury stock the Company may purchase, commodity hedge agreements, and loans and investments in its consolidated subsidiaries and limited partnerships. The credit facility is collateralized by the mortgaged properties and any other property, including interests of the Company s limited partnerships, that was considered in determining the borrowing base in effect. The Company is required to mortgage, and grant a security interest in, consolidated proved oil and gas properties.

The borrowings made within the credit facility may be placed in a base rate loan or LIBO rate loan. The rates applied may be a combination of the agent defined base rate, a flat rate of 2% to 3%, federal fund rates, or LIBO rates and are adjusted by applicable margins, between 1.25% and 3.25%, tied to the Company s borrowing base utilization.

As of December 31, 2010, the credit facility borrowing base was $100 million. The Company s borrowing rates in the credit facility at December 31, 2010 include a floor of 2% to 3% plus the current applicable margin utilization rates that range from 1.75% to 2.0%, depending on the type of active loan. The Company had in place two LIBO rate loans and one base rate loan at December 31, 2010 with effective rates of 4.75% to 5%.

At December 31, 2010, the outstanding balance of the Company s bank debt was $73.1 million under the credit facility, with an additional availability of $26.90 million. The combined weighted average interest rates paid on outstanding bank borrowings subject to interest were 6.09% during 2010 as compared to 5.59% during 2009.

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 commenced in April 2008, 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 were 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. These interest swap agreements expired in April 2010, and they have not been replaced.

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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 bank debt is paid off. PEC further agreed it will not secure debt in excess of $112 million under such credit facility without prior consent of the private lender. This facility was amended on July 21, 2010 and will mature on November 1, 2014. The facility termination will be accelerated if there is a change in control or management of PrimeEnergy Corporation; borrowings bear interest at a rate of 10% per annum. The private lender is entitled to additional consideration of Company stock based upon a percentage of the outstanding balance if by the last day of each calendar year commencing with December 30, 2011 the loan is outstanding.

As of December 31, 2010 advances from this facility amounted to $20 million.

This loan was modified on January 10, 2011 with an effective date of January 3, 2011. The modifications included a payment from the borrower s offshore subsidiary to the private lender of $4 million which was made on January 18, 2011 . The second modification entitles the private lender to additional consideration of Company stock based upon a percentage of the outstanding loan balance if by June 30th of each calendar year commencing with June 30, 2012 the loan has not been paid in full and the commitment of the private lender to make further advances to the borrower has been terminated.

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
2011	$ 764,000
2012	555,000
2013	434,000
2014	16,000
Total minimum payments	$ 1,769,000

Rent expense for office space for the years ended December 31, 2010 and 2009 was $787,000 and $684,000, respectively.

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2010 and 2009 is as follows:

	2010	2009
Asset retirement obligation beginning of period	$ 19,366,000	$ 19,541,000
Liabilities incurred	271,000	
Liabilities settled	(945,000)	(1,824,000)
Accretion expense	1,014,000	1,720,000
Revisions in estimated liabilities	(2,559,000)	(71,000)
Asset retirement obligation end of period	$ 17,147,000	$ 19,366,000

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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.

The change in the 2010 estimate is primarily due to higher commodity prices used to calculate proved reserves at December 31, 2010, which had the effect of lengthening the economic life of certain wells and decreasing what would otherwise have been the present value of future retirement obligations. 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, 2010, 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, 2010 and 2009, 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.

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9. Income Taxes

The components of the provision (benefit) for income taxes for the years ended December 31, 2010 and 2009 are as follows:

	2010	2009
Current:		
Federal	$ 849,000	$ (3,484,000)
State	220,000	351,000
Total current	$ 1,069,000	$ (3,133,000)
Deferred:		
Federal	(191,000)	(9,016,000)
State	124,000	(156,000)
Total deferred	$ (67,000)	$ (9,172,000)
Total income tax provision (benefit)	$ 1,002,000	$ (12,305,000)

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

	December 31, 2010	December 31, 2009
Current assets:		
Accrued liabilities	$ 439,000	$ 414,000
Allowance for doubtful accounts	156,000	303,000
Derivative contracts		121,000
Total current deferred income tax assets	$ 595,000	$ 838,000
Non-current assets:		
Alternative minimum tax credits	$ 5,393,000	$ 5,294,000
Net operating loss carry-forwards	438,000	3,698,000
Percentage depletion carry-forwards	2,538,000	1,101,000
Total non-current assets	$ 8,369,000	$ 10,093,000
Non-current liabilities:		
Basis differences relating to partnerships	$ 503,000	$ 491,000
Proved oil and gas properties	24,311,000	26,237,000
Total non-current liabilities	$ 24,814,000	$ 26,728,000
Net non-current deferred income tax liabilities	$ 16,445,000	$ 16,635,000

The total provision for income taxes for the years ended December 31, 2010 and 2009 varies from the federal statutory tax rate as a result of the following:

	December 31, 2010	December 31, 2009
Expected tax expense (benefit)	$ 1,277,000	$ (12,235,000)
State income tax, net of federal benefit	229,000	195,000
Percentage depletion	(504,000)	
Other, net		(265,000)
Total provision	$ 1,002,000	$ (12,305,000)

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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.

During 2010, the Company filed for a refund of federal income taxes paid in 2004 and 2005 based on a 2009 federal net operating loss and received refunds of $2,268,000. The 2009 return, as well as the carryback claim, is currently being audited by the Internal Revenue Service.

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 2010.

Oil Purchasers:		Gas Purchasers:	
Texon Distributing L.P.	19%	Unimark LLC	15%
Plains All American Inc.	62%	Cokinos Energy Corporation	16%
		Atlas Pipeline, WestTex, LLC	28%

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, 2010 and 2009:

	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, 2010
Assets				
Commodity derivative contracts			$ 3,042,000	$ 3,042,000
Total assets			$ 3,042,000	$ 3,042,000
Liabilities				
Commodity derivative contracts			$ (5,635,000)	$ (5,635,000)
Total liability			$ (5,635,000)	$ (5,635,000)

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	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)

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, 2010 and 2009.

	Year Ended December 31, 2010	2009
Net assets (liabilities) at beginning of period	$ (4,301,000)	$ 1,578,000
Total realized and unrealized losses:		
Included in earnings (a)	5,286,000	399,000
Included in other comprehensive loss		(2,312,000)
Purchases, sales, issuances and settlements	(3,578,000)	(3,966,000)
Net assets (liabilities) at end of period	$ (2,593,000)	$ (4,301,000)

(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.

The interest rate swap agreements expired in April 2010, and they have not been replaced.

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.

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Interest rate swaps derivatives continue to be treated as cash-flow hedges and are used to fix or float interest rates on existing debt. There is no remaining value for the interest rate swaps at December 31, 2010, and settlement of the swaps is recorded within interest expense.

Effect of derivative instruments on the consolidated balance sheet:

		Fair Value	
	Balance Sheet Location	**December 31, 2010**	**December 31, 2009**
Asset Derivatives:			
Derivatives not designated as hedging instruments:			
Natural gas commodity contracts	Current derivative contracts	3,038,000	657,000
Natural gas commodity contracts	Other assets		222,000
Crude oil commodity contracts	Other assets	4,000	
Total		$ 3,042,000	$ 879,000
Liability Derivatives:			
Derivatives designated as hedging instruments:			
Interest rate swap derivatives	Derivative liability short term	$	$ (335,000)
Total		$	$ (335,000)
Derivatives not designated as hedging instruments:			
Crude oil commodity contracts	Derivative liability short term	(3,048,000)	(1,953,000)
Crude oil commodity contracts	Derivative liability long term	(2,587,000)	(2,892,000)
Total		$ (5,635,000)	$ (4,845,000)
Total derivative instruments		$ (2,593,000)	$ (4,301,000)

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**	
		2010	**2009**
Derivatives designated as cash-flow hedges			
Interest rate swap derivatives	Interest expense	$ (347,000)	$ (881,000)
Crude oil commodity contracts	Oil and gas sales		1,519,000
		$ (347,000)	$ 638,000

	Location of gain/loss recognized in income	**Amount of gain/loss recognized in income**	
		2010	**2009**
Derivatives not designated as cash-flow hedge instruments			
Natural gas commodity contracts	Gain (loss) on derivative instruments	$ 2,159,000	$ 879,000
Crude oil commodity contracts	Gain (loss) on derivative instruments	$ (785,000)	$ (4,845,000)

Natural gas commodity contracts	Oil and gas sales	4,020,000	
Crude oil commodity contracts	Oil and gas sales	(442,000)	(14,000)
		$ 4,952,000	$ (3,980,000)

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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 $350,000 during 2010 and $152,000 during 2009.

Treasury stock purchases in any reported period may include shares from a related party. There were no related party treasury stock purchases during the years ended December 31, 2010 and 2009.

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

Payables owed to related parties primarily 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, 2010 and 2009 was $170,000 of accrued interest on the related party loan.

13. Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents include $6,131,000 and $5,497,000 at December 31, 2010 and 2009, respectively, of cash primarily pertaining to oil and gas revenue payments. There were corresponding accounts payable recorded at December 31, 2010 and 2009 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 $432,000 and $416,000 in 2010 and 2009, 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, 2010		
	Net Income	Number of Shares	Per share Amount
Basic	$ 2,753,000	2,929,275	$ .94
Effect of dilutive securities:			
Options		733,107	
Diluted	$ 2,753,000	3,662,382	$ .75

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	Year ended December 31, 2009		
	Net Income	Number of Shares	Per share Amount
Basic and diluted (a)	$ (23,679,000)	3,038,313	$ (7.79)

(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.

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

PRIMEENERGY CORPORATION AND SUBSIDIARIES

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2010 and 2009

(Unaudited)

	2010	2009
Developed oil and gas properties	$ 453,145,000	$ 441,035,000
Undeveloped oil and gas properties	698,000	1,322,000
	453,843,000	442,357,000
Accumulated depreciation, depletion and valuation allowance	310,809,000	268,514,000
Net capitalized costs	$ 143,034,000	$ 173,843,000

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION,

EXPLORATION AND DEVELOPMENT ACTIVITIES

Years Ended December 31, 2010 and 2009

(Unaudited)

	2010	2009
Acquisition of Properties Developed	$	$
Undeveloped	$ 727,000	$
Exploration Costs	$ 91,000	$ 136,000
Development Costs	$ 12,936,000	$ 17,474,000

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2010 and 2009

(Unaudited)

	2010	**2009**
Future cash inflows	$ 907,142,000	$ 549,104,000
Future production and development costs	(524,204,000)	(326,040,000)
Future income tax expenses	(101,501,000)	(38,229,000)
Future net cash flows	281,437,000	184,835,000
10% annual discount for estimated timing of cash flow	(134,953,000)	(82,093,000)
Standardized measure of discounted future net cash flows	$ 146,484,000	$ 102,742,000

See accompanying notes to supplementary information.

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS AND CHANGES THEREIN

RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2010 and 2009

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2010 and 2009:

For Year Ended December 31,	**2010**	**2009**
Sales of oil and gas produced, net of production costs	$ (50,279,000)	$ (35,853,000)
Net changes in prices and production costs	106,693,000	(71,402,000)
Extensions, discoveries and improved recovery	100,570,000	75,028,000
Revisions of previous quantity estimates	(7,270,000)	(32,725,000)
Reserves purchased, net of development costs		
Net change in development costs	(82,113,00)	45,122,000
Reserves sold	(4,633,000)	
Accretion of discount	10,274,000	11,653,000
Net change in income taxes	(30,047,000)	(6,940,000)
Changes in production rates (timing) and other	547,000	1,325,000
Net change	43,742,000	(13,792,000)
Standardized measure of discounted future net cash flow:		
Beginning of year	102,742,000	116,534,000
End of year	$ 146,484,000	$ 102,742,000

See accompanying notes to supplementary information.

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RESERVE QUANTITY INFORMATION

Years Ended December 31, 2010 and 2009

(Unaudited)

	2010		2009	
	Oil (bbls.)	**Gas (Mcf)**	**Oil (bbls.)**	**Gas (Mcf)**
Proved developed and undeveloped reserves:				
Beginning of year	6,087,000	45,413,000	5,317,000	55,338,000
Extensions, discoveries and improved recovery	4,053,000	16,658,000	2,136,000	10,198,000
Revisions of previous estimates	(911,000)	173,000	(726,000)	(12,994,000)
Purchases				
Reserves sold	(717,000)	(2,959,000)		
Production	(627,000)	(5,939,000)	(640,000)	(7,129,000)
End of year	7,885,000	53,346,000	6,087,000	45,413,000
Proved developed reserves	5,233,000	41,946,000	4,476,000	38,389,000

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2010 and 2009

(Unaudited)

	2010	**2009**
Revenue:		
Oil and gas sales	$ 85,263,000	$ 69,343,000
Costs and expenses:		
Lease operating expense	34,984,000	33,490,000
Exploration costs	91,000	136,000
Depreciation and Depletion	40,218,000	48,782,000
Income tax expense (benefit)	1,900,000	(4,597,000)
	77,193,000	77,811,000
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 8,070,000	$ (8,468,000)

See accompanying notes to supplementary information.

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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 2010 and 2009 extensions and discoveries reflect the successful drilling activity in the Company s West Texas area.