PRIMEENERGY CORP
Form 10-K
April 03, 2009

Table of Contents

Index to Financial Statements

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

Or

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

Commission File Number 0-7406

PrimeEnergy Corporation

(Exact name of registrant as specified in its charter)

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

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

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

Securities registered pursuant to Section 12(g) of the Act:

Common Stock, par value $.10 per share

(Title of Class)

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. **Yes** ¨ **No x**

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 of Section 15(d) of the Act. **Yes** ¨ **No x**

Indicate whether Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. **Yes x No** ¨

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

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

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). **Yes** ¨ **No** x

The aggregate market value of the voting stock of the Registrant held by non-affiliates, computed by reference to the average bid and asked price of such common equity as of the last business day of the Registrant s most recently completed second fiscal quarter, was $34,989,461.

The number of shares outstanding of each class of the Registrant s Common Stock as of April 2, 2009 was 3,041,513 shares, Common Stock, $0.10 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s proxy statement to be furnished to stockholders in connection with its Annual Meeting of Stockholders to be held in June 2009, are incorporated by reference in Part III hereof.

Table of Contents

Index to Financial Statements

TABLE OF CONTENTS

Table of Contents

Index to Financial Statements

PrimeEnergy Corporation

FORM 10-K ANNUAL REPORT

For the Fiscal Year Ended

December 31, 2008

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, 2008, the Company had net capitalized costs related to oil and gas properties of $212.1 million, including $2.4 million of undeveloped properties. Total expenditures for the acquisition, exploration and development of the Company s properties during 2008 were $53.7 million of which $649,000 related to

Table of Contents

Index to Financial Statements

exploration costs expensed during 2008. Proved reserves as of December 31, 2008, were 87 BCFe of gas which consisted of 98.6% proved developed reserves and 1.4% proved undeveloped reserves.

Significant 2008 activity

During 2008, we participated in drilling a total of 71 gross (41.68 net) wells, all of which were successful completions.

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

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

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

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

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

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

Well Operations

The Company s operations are conducted through a central office in Houston, Texas, and district offices in Houston and Midland, Texas, Oklahoma City, Oklahoma, and Charleston, West Virginia. The Company currently operates 1,645 oil and gas wells, 418 through the Houston office, 283 through the Midland office, 446 through the Oklahoma City office and 498 through the Charleston, West Virginia office. Substantially all of the wells operated by the Company are wells in which the Company has an interest.

The Company operates wells pursuant to operating agreements which govern the relationship between the Company as operator and the other owners of working interests in the properties, including the Partnerships, Trusts and joint venture participants. For each operated well, the Company receives monthly fees that are

Table of Contents

Index to Financial Statements

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 2,587. This number, as well as the number of remaining partnerships noted above, has decreased in recent years as the Company continues to buy back limited partner interest.

Regulation

Regulation of Transportation and Sale of Natural Gas:

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

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

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

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

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

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

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

Regulation of Transportation of Oil:

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

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

Table of Contents

Index to Financial Statements

Regulation of Production:

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

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

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

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

Taxation

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

See Notes 1 and 9 to the consolidated financial statements included in this Report for a discussion of accounting for income taxes.

Competition and Markets

The business of acquiring producing properties and non-producing leases suitable for exploration and development is highly competitive. Competitors of the Company, in its efforts to acquire both producing and

Table of Contents

Index to Financial Statements

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.	25%
Plains All American Inc.	61%
Gas Purchasers:	
Unimark LLC	12%
Cokinos Energy Corporation	48%

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

Environmental Matters

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

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

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

- Impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties or the imposition of injunctive relief. Changes in environmental laws and regulations occur regularly, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the oil and natural gas industry in general. While we believe that we are in substantial compliance

8

Table of Contents

Index to Financial Statements

with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, there is no assurance that this trend will continue in the future.

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

- unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water;
- capital costs to drill exploration and development wells primarily related to the management and disposal of drilling fluids and other oil and natural gas exploration wastes; and
- capital costs to construct, maintain and upgrade equipment and facilities.

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

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

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

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

Oil Pollution Act of 1990. The Oil Pollution Act of 1990, as amended (the OPA), and regulations there under impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters, and adjoining shorelines or in the exclusive economic zone of the United States. Liability under OPA is strict, and under certain circumstances joint and several, and potentially unlimited. A responsible party includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities

Table of Contents

Index to Financial Statements

related to an oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150.0 million depending on the risk represented by the quantity or quality of oil that is handled by the facility. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA s requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA s financial responsibility and other operating requirements will not have a material adverse effect on us.

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

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

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

Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Table of Contents

Index to Financial Statements

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

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

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

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

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

Air Pollution Control. The Clean Air Act and state air pollution laws adopted to fulfill its mandates provide a framework for national, state and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants subject to federal and state air pollution control laws. These laws require utilization of air emissions

Table of Contents

Index to Financial Statements

abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Air emissions associated with offshore activities are projected using a matrix and formula supplied by MMS, which has primacy from the Environmental Protection Agency for regulating such emissions.

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

Employees

At March 26, 2009, the Company had 232 full-time and 17 part-time employees, 21 of whom were employed by the Company at its principal offices in Stamford, Connecticut, 35 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 193 employees who were primarily involved in the district operations of the Company in Houston and Midland, Texas, Oklahoma City, Oklahoma and Charleston, West Virginia.

Item 1A. RISK FACTORS.

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

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

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

- the level of consumer product demand;
- weather conditions;
- political conditions in natural gas and oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;

actions of governmental authorities;

pipeline capacity constraints;

inventory storage levels;

domestic and foreign governmental regulations;

12

Table of Contents

Index to Financial Statements

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

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

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

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

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

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

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

- our financial resources and results; and

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

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

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

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is

Table of Contents

Index to Financial Statements

complex and inherently uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysic, engineering and production data. As a result, estimates of different engineers may vary. In addition, the extent, quality and reliability of this technical data can vary. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

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

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

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

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

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

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

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

Our business involves a variety of operating risks, including:

blowouts, cratering and explosions;

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

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

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

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

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

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

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

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

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

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

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

Table of Contents

Index to Financial Statements

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

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

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

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

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

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

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

Item 1B. UNRESOLVED STAFF COMMENTS.

The Company is a 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.

Table of Contents

Index to Financial Statements

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, 2008.

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil	2	1.5				
Gas					5	3.750
Dry			1	.375	1	.400
Development:						
Oil	69	40.18	30	13.88	41	22.141
Gas					28	11.664
Dry						
Total:						
Oil	71	41.68	30	13.88	41	22.141
Gas					33	15.414
Dry			1	.375	1	.400
	71	41.68	31	14.255	75	37.955

Oil and Gas Production

As of December 31, 2008, 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	997	407
Gas Wells	1,186	517
Producing Acres	315,640.83	106,589.27

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

The following table shows the Company s net production of crude oil and natural gas for each of the three years ended December 31, 2008. 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.

	2008	2007	2006
Oil (barrels)	658,000	561,000	456,000
Gas (Mcf)	8,899,000	11,312,000	6,411,000

Table of Contents

Index to Financial Statements

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, 2008.

	2008	2007	2006
Average sales price per barrel	$ 84.43	66.94	61.10
Average sales price Per Mcf	$ 8.93	7.50	6.83
Average production costs per net equivalent barrel (1)	$ 19.92	14.24	16.62

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

Undeveloped Acreage

The following table sets forth the approximate gross and net undeveloped acreage in which the Company has leasehold, mineral and royalty interests as of December 31, 2008. Undeveloped acreage is that acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

	Leasehold Interests		Mineral Interests		Royalty Interests	
State	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Colorado			799	23		
Gulf of Mexico	85,696	54,288				
Louisiana					295	1
Montana			14,304	60		
Nebraska			2,554	331		
North Dakota			640	1		
Oklahoma	4,176	1,895	320	0	2,880	24
Texas	1,826	1,371	640	2		
West Virginia	220	41				
Wyoming					140	35
TOTAL	91,918	57,595	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, 2008. 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)
2006	4,986,000	75,434,000	219,000	2,479,000	5,205,000	77,913,000
2007	5,640,000	58,814,000	952,000	2,598,000	6,592,000	61,412,000
2008	5,317,000	54,140,000		1,198,000	5,317,000	55,338,000

[Table of Contents](#)

[Index to Financial Statements](#)

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, 2008, are summarized as follows (figures rounded):

	Proved Developed		Proved Undeveloped		Total			
As of 12-31	Future Net Revenue	Present Value Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	Standardized Measure of Discounted Cash flow
2006	$ 409,525,000	269,139,000	13,836,000	7,077,000	423,361,000	276,216,000	58,167,000	218,049,000
2007	$ 449,372,000	266,405,000	60,392,000	21,062,000	509,764,000	287,467,000	62,007,000	225,460,000
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

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

Proved developed oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The Company s reserves include amounts attributable to minority interests in the Partnerships. These interests represent less than 10% of the Company s reserves.

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

The spot price for gas at December 31, 2008 and 2007 was $5.62 and $6.79 per MMBTU, respectively. The range of spot prices during the year 2008 was a low of $5.40 and a high of $13.28 and the average was $8.84. The range during the first quarter of 2009 has been from $3.72 to $6.10, with an average of $4.57. The recent futures market prices have traded above $3.72 per MMBTU.

The NYMEX price for oil at December 31, 2008 and 2007 was $44.60 and $96.01 per barrel, respectively. The range of NYMEX prices during the year 2008 was a low of $33.87 and a high of $145.18 and the average was $99.63. The range during the first quarter of 2009 has been from $33.98 to $54.34, with an average of $43.11. The recent futures market prices have fluctuated around $52.00.

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

Since January 1, 2009, 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.

Table of Contents

Index to Financial Statements

District Information

The following table presents certain reserve, production and well information as of December 31, 2008.

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Offshore	Other	Total
Proved Reserves at Year End (Mmcfe)							
Developed	12,516	7,850	22,486	32,750	9,345	1,098	86,045
Undeveloped					1,198		1.198
Total	12,516	7,850	22,486	32,750	10,543	1,098	87,243
Average Daily Production (Mmcfe per day)	2	3	7	10	12	1	35
Gross Wells	732	506	734	394	19	81	2,397
Net Wells	377	181	280	147	10	15	1,011
Gross Operated Wells	498	333	446	283	17	68	1,645

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, 2008, we had 732 wells (377 net), of which 498 wells are operated by us. There are multiple producing intervals that include the Big Lime, Injun, Blue Monday, Weir, Berea, Gordon and Devonian Shale formations at depths primarily ranging from 1,600 to 5,600 feet. Average net daily production in 2008 was 2,290 Mcfe. While natural gas production volumes from Appalachian reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of Appalachian reserves is relatively long. At December 31, 2008, we had 12.5 Bcfe of proved reserves (substantially all natural gas) in the Appalachian region, constituting 14% of our total proved reserves. This region is managed from our office in Charleston, West Virginia.

Gulf Coast Region

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in Louisiana, southeast Texas and south Texas. This region is managed from our office in Houston. Principal producing intervals are in the Marg Tex, Wilcox, Pettit, Glenrose, Woodbine, San Miguel, Olmos, and Yegua formations at depths ranging from 3,000 to 12,500 feet. We had 506 wells (181 net) in the Gulf Coast region as of December 31, 2008, of which 333 wells are operated by us. Average daily production in 2008 was 2,596 Mcfe. At December 31, 2008, we had 7.9 Bcfe of proved reserves (75% natural gas) in the Gulf Coast region, which represented 9% of our total proved reserves.

Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. As of December 31, 2008, we had 734 wells (280 net) in the Mid-Continent area, of which 446 wells are operated by us. Principal producing intervals in the Mid-Continent are in the Roberson, Avant, Skinner, Sycamore, Bromide, McLish, Hunton, Mississippian, Oswego, Red Fork, and Chester formations at depths ranging from 1,100 to 10,500 feet. Average net daily production in 2008 was 7,420 Mcfe. At December 31, 2008, we had 22.5 Bcfe of proved reserves (67% natural gas) in the Mid-Continent area, or 26% of our total proved reserves. This region is managed from our office in Oklahoma City.

West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas and New Mexico. As of December 31, 2008, we had 394 wells (147 net) in the West Texas area, of which 283 wells are operated by us.

Table of Contents

Index to Financial Statements

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 2008 was 10,382 Mcfe. At December 31, 2008, we had 32.8 Bcfe of proved reserves (34% natural gas) in the West Texas area, or 38% of our total proved reserves. This region is managed from our office in Midland, Texas.

Offshore Gulf of Mexico

Our development, exploitation, exploration and production activities in the Offshore Gulf of Mexico are primarily concentrated in the western gulf area in shallow water. This region is managed from our office in Houston. Principal producing intervals are in the Pleistocene to Miocene formations at depths ranging from 750 to 12,500 feet. We had 19 wells (10 net) in the Offshore Gulf of Mexico region as of December 31, 2008, of which 17 wells are operated by us. Average daily production in 2008 was 12,182 Mcfe. At December 31, 2008, we had 10.5 Bcfe of proved reserves (substantially all natural gas) in the Offshore Gulf of Mexico region, which represented 12% of our total proved reserves.

Acreage subject to Expiration in the next three years

	2009		**2010**		**2011**	
State	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
GULF OF MEXICO	12,757	8,894			28,800	21,600
OKLAHOMA	780	780	170	85		
TEXAS	1,743	1,212		24		
NEW MEXICO	3,920	3,287	320	87		
WEST VIRGINIA				11		
COLORADO			211			
TOTAL	19,200	14,173	701	207	28,800	21,600

Item 3. LEGAL PROCEEDINGS.

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

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

No matters were submitted during the fourth quarter of the fiscal year ended December 31, 2008, to a vote of the Company s security-holders through the solicitation of proxies or otherwise.

Table of Contents

Index to Financial Statements

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, 2008, were as follows:

2008	High	Low	2007	High	Low
First Quarter	$ 58.00	$ 52.08	First Quarter	$ 64.97	$ 50.10
Second Quarter	$ 64.50	$ 52.00	Second Quarter	$ 64.90	$ 54.75
Third Quarter	$ 82.38	$ 50.68	Third Quarter	$ 58.60	$ 53.00
Fourth Quarter	$ 77.62	$ 44.63	Fourth Quarter	$ 56.95	$ 52.43

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

The number of record holders of the Company s Common Stock as of March 30, 2009, was 717.

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

Issuer Purchases of Equity Securities

In December 1993, we announced that our Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of our Common Stock from time-to-time, in open market transactions or negotiated sales. A total of 2,700,000 shares have been authorized, to date, under this program. Through December 31, 2008, we repurchased a total of 2,503,277 shares under this program for $33,660,798 at an average price of $13.45 per share. Additional purchases of shares may occur as market conditions warrant. We expect future purchases will be funded with internally generated cash flow or from working capital.

2008 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Program
January	60,684	$ 50.06	224,871
February	558	54.68	224,313
March	10,465	50.25	213,848
April	5,500	58.05	208,348
May	435	61.22	207,913
June	6,726	55.62	201,187
July	1,777	55.14	199,410
August	200	64.04	199,210
September			199,210
October	735	54.97	198,475
November	1,036	49.62	197,439
December	716	49.20	196,723
Total/Average/Remainder	88,832	$ 51.24	

Table of Contents

Index to Financial Statements

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 financial statements of the Company and notes thereto. The Company s subsidiaries are defined in Note 1 of the financial statements.

Liquidity And Capital Resources:

Cash flow provided by operations for the year ended December 31, 2008, was $84 million, compared to $95 million in the prior year.

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

Our realized oil and gas prices vary due to world political events, supply and demand of products, product storage levels, and weather patterns. We sell the vast majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility we sometimes lock in prices for some portion of our production through the use of financial instruments.

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

The Company has in place both a stock repurchase program and a limited partnership interest repurchase program. Spending under these programs in 2008 was $5.03 million. The Company expects to expend substantially less in 2009 because of the drop in energy prices.

The Company currently maintains two credit facilities totaling $360 million, with a combined current borrowing base of $126.37 million. The bank reviews the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a redetermined estimate of proved oil and gas reserves. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial covenants defined in the agreement. We are currently in compliance with these financial covenants. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable.

During the second quarter of 2008, the Company s offshore subsidiary arranged a subordinated credit facility with a private lender controlled by a director of the Company. The facility provides availability of $50 million and is secured by properties released by the bank and pledged under this agreement. The current advances under this credit facility are $20 million due January 2010.

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

Table of Contents

Index to Financial Statements

further expand its oilfield servicing revenues through additional investment in field service equipment. However, the majority of the Company s capital spending is discretionary, and the ultimate level of expenditures will be dependent on the Company s assessment of the oil and gas business environment, the number and quality of oil and gas prospects available, the market for oilfield services, and oil and gas business opportunities in general.

Critical Accounting Estimates:

Proved Oil and Gas Reserves

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

Depreciation, Depletion and Amortization for Oil and Gas Properties

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

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

Results of Operations:

2008 as compared to 2007

The Company had net income of $541,000 in 2008 as compared to $7,920,000 in 2007. The significant components of net income are discussed below.

Oil and gas sales were $135,036,000 in 2008 as compared to $122,361,000 in 2007. A chart summarizing oil and gas production and revenue is presented below.

	2008	2007	Increase (Decrease)
Barrels of Oil Produced	658,000	561,000	97,000
Average Price Received (rounded)	$ 84.43	$ 66.94	$ 17.49
Oil Revenue	$ 55,554,000	$ 37,553,000	$ 18,001,000
Mcf of Gas Produced	8,899,000	11,312,000	(2,413,000)
Average Price Received (rounded)	$ 8.93	$ 7.50	$ 1.43