ABRAXAS PETROLEUM CORP
Form 10-K
February 24, 2009

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

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

Commission File Number 001-16071

ABRAXAS PETROLEUM CORPORATION
(Exact name of Registrant as specified in its charter)

Nevada (State or Other Jurisdiction of Incorporation or Organization)	74-2584033 (I.R.S. Employer Identification Number)

18803 Meisner Drive
San Antonio, TX 78258
(Address of principal executive offices)

(210) 490-4788
Registrant's telephone number, including area code

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class:	Name of each exchange on which registered:
Common Stock, par value $.01 per share	NASDAQ Stock Market

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.Yes No

Indicate by check mark whether the 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 xNo

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. Yes xNo

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer x
Non-accelerated filer (Do not mark if a smaller reporting company)	Smaller reporting company

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

As of June 30, 2008, the aggregate market value of the common stock held by non-affiliates of the registrant was $243,774,232 based on the closing sale price as reported on the American Stock Exchange.

As of February 20, 2009, there were 49,621,711 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2009 Annual Meeting of Shareholders to be held on May 21, 2009.	Part III

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Forward-Looking Information

We make forward-looking statements throughout this document. Whenever you read a statement that is not simply a statement of historical fact (such as statements including words like “believe”, “expect”, “anticipate”, “intend”, “plan”, “s “estimate”, “could”, “potentially” or similar expressions), you must remember that these are forward-looking statements and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this document is generally located in the material set forth under the heading “Management’s Discussion and Analysis of Financial Condition and Results of Operations” but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- our success in development, exploitation and exploration activities;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- prices for oil and gas;
- our ability to raise equity capital or incur additional indebtedness;
- economic and business conditions;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our restrictive debt covenants;
- our acquisition and divestiture activities;
- results of our hedging activities; and
- other factors discussed elsewhere in this document.

Part I

Item 1. Business

In this report, PV-10 means estimated future net revenue discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the Securities and Exchange Commission. A Mcf is one thousand cubic feet of gas. MMcf is used to designate one million cubic feet of gas and Bcf refers to one billion cubic feet of gas. Mcfe means thousands of cubic feet of gas equivalents, using a conversion ratio of one barrel of oil to six Mcf of gas. MMcfe means millions of cubic feet of gas equivalents and Bcfe means billions of cubic feet of gas equivalents. MMBtu means million British Thermal Units. The term Bbl means one barrel of oil or natural gas liquids and MBbls is used to designate one thousand barrels of oil or natural gas liquids.

Information contained in this report represents the operations of Abraxas Petroleum Corporation and Abraxas Energy Partners, L.P., which we refer to as the Partnership or Abraxas Energy Partners, which are consolidated for financial reporting purposes. The interest of the 52.7% owners of the Partnership is presented as minority interest. Abraxas beneficially owns the remaining 47.3% of the partnership interests. Abraxas has determined that based on its control of the general partner of the Partnership, this 47.3% owned entity should be consolidated for financial reporting purposes. The terms "Abraxas" or "Abraxas Petroleum" refer only to Abraxas Petroleum Corporation and the terms "we," "us," "our," or the "Company," refer to Abraxas Petroleum Corporation, together with its consolidated subsidiaries including Abraxas Energy Partners, L.P., unless the context otherwise requires.

General

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We are an independent energy company primarily engaged in the development and production of oil and gas. Historically, we have grown through the acquisition and subsequent development and exploration of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

At December 31, 2008, our properties were located in the Rocky Mountain, Mid-Continent, Permian Basin and Gulf Coast regions of the United States.

Our Rocky Mountain properties consist of the following:

- Northern Rockies—Our properties in the Northern Rockies are located in the Williston Basin of North Dakota, South Dakota and Montana and consist of wells that produce oil from Paleozoic-aged carbonate reservoirs from the Madison formation at 8,000 feet down to the Red River formation at 12,000 feet, including the Bakken at 9,000 feet.

- Southern Rockies—Our properties in the Southern Rockies are located in the Green River, Powder River and Uinta Basins of Wyoming, Colorado and Utah and consist of wells that produce oil from Cretaceous-aged fractured shales in the Mowry and Niobrara formation and oil and gas from Cretaceous-aged sandstones in the Turner, Muddy and Frontier formations. Well depths range from 7,000 feet down to 10,000 feet.

We have 894 gross (110 net) producing wells in the Rocky Mountain region.

Our Mid-Continent properties consist of the following:

- Arkoma Basin—Our properties in the Arkoma Basin are located in Oklahoma and Arkansas and consist of wells that mainly produce gas from Hartshorne coals at 3,000 feet.

- Anadarko Basin—Our properties in the Anadarko Basin are located in Oklahoma and the Texas Panhandle and consist of wells that mainly produce gas from Pennsylvanian-aged sandstones (Atoka/Morrow) from depths of up to 18,000 feet.

- ARK-LA-TEX—Our properties in the ARK-LA-TEX region principally produce from the East Texas/North Louisiana Basins and include wells that produce oil and gas from various formations.

We have 602 gross (103 net) producing wells in the Mid-Continent region.

Our Permian Basin properties consist of the following:

- ROC Complex—Our properties in the ROC Complex are located in Pecos, Reeves and Ward Counties and consist of wells that produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet.

- Oates SW—Our properties in the Oates SW area are located in Pecos County and consist of wells that produce gas from the Devonian formation at a depth of approximately 13,500 feet.

- Eastern Shelf – Our properties in the Eastern Shelf are predominately located in Coke, Scurry and Mitchell Counties and consist of wells that produce oil and gas from the Strawn Reef formation at 5,000 to 6,000 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet.

We have 236 gross (160 net) producing wells in the Permian Basin region.

Our Gulf Coast properties consist of the following:

- Edwards— Our properties in the Edwards trend are located in DeWitt and Lavaca Counties and consist of wells that produce gas from the Edwards formation at a depth of 13,500 feet.

- Portilla—The Portilla field – located in San Patricio County, was discovered in 1950 by The Superior Oil Company, predecessor to Mobil Oil Corporation, and consists of wells that produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet.

- Wilcox – Our properties in the Wilcox are located in Goliad, Bee and Karnes Counties and consist of wells that produce gas from various sands in the Wilcox formation at depths ranging from 8,000 to 11,000 feet.

We have 79 gross (55 net) producing wells in the Gulf Coast region.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices of oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other oil-producing and gas-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices of oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenue, profitability and cash flow from operations. You should read the discussion under "Risk Factors – Risks Relating to Our Industry — Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows, profitability and growth" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies" for more information relating to the effects of decreases in oil and gas prices on us. To help mitigate the impact of commodity price volatility, we hedge a portion of our production through the use of fixed price swaps. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – General – Commodity Prices and Derivative Activities" and Note 14 of the notes to our consolidated financial statements for more information regarding our derivative activities.

Substantially all of our oil and gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2008, two purchasers accounted for approximately 29% of our oil and gas sales. We believe that there are numerous other customers available to purchase our oil and gas and that the loss of one or more of these purchasers would not materially affect our ability to sell oil and gas.

Regulation of Oil and Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our operations are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by industry specific price controls, taxes, conservation, safety, environmental, and other laws relating to the petroleum industry, and by changes in such laws and by constantly changing administrative regulations.

Price Regulations

In the past, maximum selling prices for certain categories of oil, gas and natural gas liquids were subject to significant federal regulation. At the present time, however, all sales of our oil and gas produced under private contracts may be sold at market prices. Congress could, however, re-enact price controls in the future. If controls that limit prices to below market rates are instituted, our revenue could be adversely affected.

Gas Regulation

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Historically, the gas industry as a whole has been more heavily regulated than the oil or other liquid hydrocarbons markets. Most regulations focus on transportation practices. Currently, the Federal Energy Regulatory Commission ("FERC") requires each interstate pipeline to, among other things, "unbundle" its traditional bundled sales services and create and make available on an open and nondiscriminatory basis numerous constituent services (such as storage services, firm and interruptible transportation services, and standby sales and gas balancing services), and to adopt a ratemaking methodology to determine appropriate rates for those services. To the extent the pipeline company or its sales affiliate markets gas as a merchant, it does so pursuant to private contracts in direct competition with all of the sellers, such as us; however, pipeline companies and their affiliates are not required to remain "merchants" of gas, and most of the interstate pipeline companies have become "transporters only", although many have affiliated marketers.

Transportation pipeline availability and shipping cost are major factors affecting the production and sale of gas. Our physical sales of gas are affected by the actual availability, terms and cost of pipeline transportation. The price and terms for access into the pipeline transportation systems remain subject to extensive Federal regulation. Although FERC does not directly regulate our production and marketing activities, it does affect how buyers and sellers gain access to and use of the necessary transportation facilities and how we and our competitors sell gas in the marketplace. FERC continues to review and modify its regulations regarding the transportation of gas. The 2005 Energy Policy Act recently authorized FERC to allow gas companies subject to the FERC's Natural Gas Act jurisdiction to provide gas storage and storage-related services at market-based rates for new storage capacity of a storage facility placed in service after the date of the Act's August 2005 passage, thereby enhancing competition in the market for interstate gas storage service.

In recent years FERC also has pursued a number of important policy initiatives which could significantly affect the marketing of gas in the United States. Most of these initiatives are intended to enhance competition in gas markets. FERC rules encouraging "spin downs", or the breakout of unregulated gathering activities from regulated transportation services, may have the adverse effect of increasing the cost of doing business on some in the industry, including us, as a result of the geographic monopolization of certain facilities by their new, unregulated owners. Note, however; that FERC is pursuing an inquiry into whether it should revise its test for determining whether and under what circumstances FERC may reassert jurisdiction over gas gathering companies that have been "spun-down" from an affiliated interstate gas pipeline to prevent abusive practices by the gatherer and its pipeline affiliate. Any action taken by FERC in this proceeding will be intended by it to enhance competition in the gas transportation sector. As to all FERC initiatives, the ongoing, or, in some instances, preliminary and evolving nature of such matters makes it impossible at this time to predict their ultimate impact on our business. However, we do not believe that any FERC initiatives will affect us any differently than other gas producers and marketers with which we compete.

FERC decisions involving onshore facilities are more liberal in their reliance upon traditional tests for determining what facilities are "gathering" and therefore are exempt from federal regulatory control. In many instances, what was in the past classified as "transmission" may now be classified as "gathering." We ship certain of our gas through gathering facilities owned by others. Although FERC decisions create the potential for increasing the cost of shipping our gas on third party gathering facilities, our shipping activities have not been materially affected by these decisions.

In summary, all FERC activities related to the transportation of gas result in improved opportunities to market our physical production to a variety of buyers and market places, while at the same time increasing access to pipeline transportation and delivery services. Additional proposals and proceedings that might affect the gas industry in the United States are considered from time to time by Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The oil and gas industry historically has been very heavily regulated; thus there is no assurance that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future.

State and Other Regulation

All of the jurisdictions in which we own producing oil and gas properties have statutory provisions regulating the exploration for and production of oil and gas. These include provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells and provisions

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relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units on an acreage basis and the density of wells which may be drilled and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and gas wells generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. Some states, such as Texas and Oklahoma, have, in recent years, reviewed and substantially revised methods previously used to make monthly determinations of allowable rates of production from fields and individual wells. The effect of all of these conservation regulations has the potential to limit the speed, timing and amounts of oil and gas we can produce from our wells, and to limit the number of wells or the location at which we can drill.

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take or service requirements, but does not generally entail rate regulation. In the United States, gas gathering has received greater regulatory scrutiny at both the state and federal levels in the wake of the interstate pipeline restructuring under FERC Order 636. For example, the Texas Railroad Commission enacted a Natural Gas Transportation Standards and Code of Conduct to provide regulatory support for the State's more active review of rates, services and practices associated with the gathering and transportation of gas by an entity that provides such services to others for a fee, in order to prohibit such entities from unduly discriminating in favor of their affiliates.

For those operations on Federal or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various federal agencies. In addition, on Federal Lands in the United States, the Minerals Management Service ("MMS") prescribes or severely limits the types of post production costs that are deductible costs for purposes of royalty valuation of production sold off the lease. In particular, MMS prohibits deduction of costs associated with marketer fees, cash out and other pipeline imbalance penalties, and or long-term storage fees. Between 2003 and 2005, the MMS promulgated new rules and procedures for determining the value of oil produced from federal lands for purposes of calculating royalties owed to the government. As a general matter the oil and gas industry as a whole has resisted these rules under an assumption that royalty burdens will substantially increase. At this time, we are unable to predict the ultimate cost and effects of these new rules on our operations.

Environmental Matters

Our operations are subject to numerous federal, state and local laws and regulations controlling the generation, use, storage and discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences; restrict the types, quantities, and concentrations of various substances that can be released into the environment in connection with drilling, production, and gas processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, and other protected areas; require remedial measures to mitigate pollution from historical and on-going operations such as use of pits and plugging of abandoned wells; restrict injection of liquids into subsurface strata that may contaminate groundwater; and impose substantial liabilities for pollution resulting from our operations. Environmental permits required for our operations may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations and permits, and violations are subject to injunction, civil fines, and even criminal penalties. Our management believes that we are in substantial compliance with current environmental laws and regulations, and that we will not be required to make material capital expenditures to comply with existing laws. Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on us as well as the oil and gas industry in general, and thus we are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

We are not currently involved in any administrative, judicial or legal proceedings arising under domestic or foreign federal, state, or local environmental protection laws and regulations, or under federal or state common law, which would have a material adverse effect on our financial position or results of

operations. Moreover, we maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. A serious incident of pollution may result in the suspension or cessation of operations in the affected area.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as Superfund, and which we refer to as CERCLA, and comparable state statutes impose strict, joint, and several liability, without regard to fault or legality of conduct, on certain classes of persons who are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of a disposal site or sites where a release occurred and companies that generated, disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, such persons or companies may be retroactively liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the EPA and in some cases third parties, to take actions 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. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment.

In the course of the ordinary operations of our properties, certain wastes may be generated 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. Although CERCLA currently contains a “petroleum exclusion” from the definition of “hazardous substance,” state laws affecting our operations impose cleanup liability relating to petroleum and petroleum related products, including oil cleanups.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although Abraxas Petroleum has utilized standard industry operating and disposal practices at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we owned or leased or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA (as defined below), 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.

Oil Pollution Act of 1990. United States federal regulations also require certain owners and operators of facilities that store or otherwise handle oil, such as us, to prepare and implement spill prevention, control and countermeasure plans and spill response plans relating to possible discharge of oil into surface waters. The federal Oil Pollution Act (“OPA”) contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. For facilities that may affect state waters, OPA requires an operator to demonstrate $10 million in financial responsibility. State laws mandate oil cleanup programs with respect to contaminated soil. 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. U.S. Environmental Protection Agency regulations address the disposal of oil and 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 gas wastes are regulated by the Underground Injection Control program under the Safe Drinking Water Act. If wastes are classified as hazardous, they must be properly transported, using a uniform hazardous waste manifest, documented, and disposed of at an approved hazardous waste facility. We have coverage under the applicable Clean Water Act permitting requirements for discharges associated with exploration and development activities.

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

Safe Drinking Water Act. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and 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 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.

Clean Air Act. The Clean Air Act, which we refer to as the CAA, and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operations of our properties utilize equipment that emits air pollutants which may be 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.

Permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas, may require oil and gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. Oil and gas exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

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The Kyoto Protocol to the United Nations Framework Convention on Climate Change, or the Protocol, became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as “greenhouse gases,” that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol; however, Congress has recently considered proposed legislation directed at reducing “greenhouse gas emissions,” and certain states have adopted legislation, regulations and/or initiatives addressing greenhouse gas emissions from various sources, primarily power plants. Additionally, on April 2, 2007, the U.S. Supreme Court ruled in Massachusetts v. EPA that the EPA has authority under the CAA to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks). The Court also held that greenhouse gases fall within the CAA’s definition of “air pollutant,” which could result in future regulation of greenhouse gas emissions from stationary sources, including those used in oil and gas exploration and production operations. The oil and gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our properties are not adversely impacted by the current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

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 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 various states in which we operate.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, which we refer to as NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. If we were to conduct any exploration and production activities on federal lands in the future, those activities would need to obtain governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and gas projects.

Endangered Species Act. The Endangered Species Act, which we refer to as the ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our facilities may be located in areas that may be designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the discovery of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Abandonment Costs. All of our oil and gas wells will require proper plugging and abandonment when they are no longer producing. We post bonds with most regulatory agencies to ensure compliance with our plugging responsibility. Plugging and abandonment operations and associated reclamation of the surface production site are important components of our environmental management system. We plan accordingly for the ultimate disposition of properties that are no longer producing.

Title to Properties

As is customary in the oil and gas industry, we make only a cursory review of title to undeveloped oil and gas leases at the time we acquire them. However, before drilling commences, we require a thorough title search to be conducted, and any material defects in title are remedied prior to the time actual drilling of a well begins. To the extent title opinions or other investigations reflect title defects, we, rather than the seller/lessor of the undeveloped property, are typically obligated to cure any title defect at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our oil and gas properties, some of which are subject to immaterial encumbrances, easements and restrictions. The oil and gas properties we own are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. We do not believe that any of these encumbrances or burdens will materially affect our ownership or use of our properties.

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Competition

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of oil and gas operations. We must compete for such resources with both major oil and gas companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our operations in the immediate future, we cannot assure you that such materials and resources will be available to us. For more information, you should read "Risk Factors – Risks Related to Our Industry – We operate in a highly competitive industry which may adversely affect our operations." and "– The unavailability or high cost of drilling rigs, equipment, supplies, insurance, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget."

Employees

As of February 13, 2009 we had 65 full-time employees. We retain independent geological, land and engineering consultants from time to time on a limited basis and expect to continue to do so in the future.

Available Information

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission. You may read and copy any document we file with the SEC at the SEC's public reference room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for information on the public reference room. The SEC maintains an internet web site that contains annual, quarterly and current reports, proxy statements and other information that issuers (including Abraxas) file electronically with the SEC. The SEC's web site is www.sec.gov.

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments filed with the Securities and Exchange Commission are available free of charge on our web site at www.abraxaspetroleum.com in the Investor Relations section as soon as practicable after such reports are filed. Information on our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

We may not be able to fund the substantial capital expenditures that will be required for us to increase reserves and production.

We must make substantial capital expenditures to develop our existing reserves and to discover new reserves. Historically, we have financed our capital expenditures primarily with cash flow from operations, borrowings under credit facilities, sales of producing properties, and sales of debt and equity securities and we expect to continue to do so in the future. Abraxas also anticipates receiving distributions of available cash from the Partnership. We cannot assure you that we will have sufficient capital resources in the future to finance all of our capital expenditures.

Volatility in oil and gas prices, the timing of both Abraxas' and the Partnership's drilling programs and drilling results will affect both Abraxas' and the Partnership's cash flow from operations as well as distributions of available cash by the Partnership to Abraxas. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet both Abraxas' and the Partnership's capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flow from operations does not increase as a result of planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and operating expenses and our planned capital expenditures would, by necessity, be decreased.

The borrowing bases under Abraxas' and the Partnership's credit facilities are determined from time to time by the lenders. Reductions in estimates of oil and gas reserves could result in a reduction in the respective borrowing bases, which would reduce the amount of financial resources available under these facilities to meet our capital requirements. Such a reduction could be the result of lower commodity prices or production, inability to drill or unfavorable drilling results, changes in oil and gas reserve engineering, the lenders' inability to agree to an adequate borrowing base or adverse changes in the lenders' practices regarding estimation of reserves.

If cash flow from operations or our borrowing bases decrease for any reason, both Abraxas' ability to undertake exploration and development activities, and the Partnerships' ability to undertake development activities could be adversely affected. The Partnership's ability to undertake exploration and development activities will also be effected by the limitation set forth in the Partnership's Credit Facility limiting capital expenditures to $12.5 million while the Partnership's Subordinated Credit Agreement remains outstanding. See "Management's Discussion and Analysis of Financial Condition and Results of Operations –Liquidity and Capital Resources – Long-Term Indebtedness." As a result, our ability to replace production may be limited. In addition, if the borrowing bases under Abraxas' and the Partnership's respective credit facilities are reduced, both Abraxas and the Partnership would be required to reduce their borrowings under their respective credit facilities so that such borrowings do not exceed such borrowing bases. This could further reduce the cash available to us for capital spending and, if either Abraxas or the Partnership did not have sufficient capital to reduce its respective borrowing level, Abraxas and/or the Partnership may be in default under their respective credit facilities.

Abraxas has sold producing properties to provide it with liquidity and capital resources in the past and both Abraxas and the Partnership may do so in the future. After any such sale, we would expect to utilize the proceeds to drill new wells on our remaining properties. If we cannot replace the production lost from properties sold with production from the remaining properties, both Abraxas' and the Partnership's cash flow from operations, including distributions of available cash from the Partnership, will likely decrease, which in turn, would decrease the amount of cash available for additional capital spending.

We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition would be adversely affected.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced. Unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, we cannot assure you that our exploration and development activities will result in increases in our proved reserves. Approximately 92% of the Partnership's and 85% of Abraxas', or 92% of the estimated ultimate recovery of our consolidated proved developed producing reserves as of December 31, 2008, had been produced. Based on the reserve information set forth in our reserve report of December 31, 2008, Abraxas' average annual estimated decline rate for its net proved developed producing reserves is 18% during the first five years, 13% in the next five years, and approximately 7% thereafter. Based on the reserve information set forth in our reserve report of December 31, 2008, the Partnership's average annual estimated decline rate for its net proved developed producing reserves is 10% during the first five years, 8% in the next five years and approximately 8% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While Abraxas has had some success in finding, acquiring and developing additional reserves, Abraxas has not always been able to fully replace the production volumes lost from natural field declines and prior property sales. For example, in 2006, Abraxas replaced only 7% of the reserves it produced. As our proved reserves and consequently our production decline, our cash flow from operations, the amount of cash distributions Abraxas receives from the Partnership and the amount that we are able to borrow under our credit facilities will also decline. In addition, approximately 65% of Abraxas' and 39% of the Partnership's total estimated proved reserves at December 31, 2008 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Even if we are successful in our development efforts, it could take several years for a significant portion of these undeveloped reserves to generate positive cash flow.

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We may not find any commercially productive oil and gas reservoirs.

We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our capital investment. Drilling for oil and gas may be unprofitable. Dry holes and wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. The inherent risk of not finding commercially productive reservoirs will be compounded by the fact that 65% of Abraxas and 39% of the Partnership's, or 46% of our consolidated total estimated proved reserves at December 31, 2008, were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. In addition, our properties may be susceptible to drainage from production by other operations on adjacent properties. If the volume of oil and gas we produce decreases, our cash flow from operations and the amount of any distributions that Abraxas may receive from the Partnership will decrease.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- shortages or delays in the availability of drilling rigs, equipment and crews;
- adverse weather conditions;
- compliance with environmental and governmental rules and regulations;
- title problems;
- unusual or unexpected geological formations;
- pipeline ruptures;
- fires, blowouts and explosions; and
- uncontrollable flows of oil or gas or well fluids.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Abraxas' credit facility and the Partnership's credit facility contain a number of significant covenants that, among other things, limit both Abraxas' and the Partnership's ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- transfer or sell assets;
- create liens on assets;

- pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- engage in transactions with affiliates;
- guarantee other indebtedness;
- make any change in the principal nature of our business;
- permit a change of control; or
- consolidate, merge or transfer all or substantially all of the consolidated assets of Abraxas and our restricted subsidiaries.

In addition, both Abraxas' credit facility and the Partnership's credit facility require each of them to maintain compliance with specified financial ratios and satisfy certain financial condition tests and the Partnership's Credit Facility limits the Partnership's capital expenditures to $12.5 million while the Partnership's Subordinated Credit Agreement remains outstanding. Both Abraxas' and the Partnership's ability to comply with these ratios and financial condition tests may be adversely affected by events beyond our control, and we cannot assure you that either Abraxas or the Partnership will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit both Abraxas' and the Partnership's ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable corporate activities.

A breach of any of these covenants or either Abraxas' or the Partnership's inability to comply with the required financial ratios or financial condition tests could result in a default under Abraxas' credit facility and/or the Partnership's credit facility. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable or favorable to us.

The marketability of our production depends largely upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities.

The marketability of our production depends in part upon processing and transportation facilities. Transportation space on such gathering systems and pipelines is occasionally limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. Our access to transportation options can also be affected by U.S. Federal and state regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the financial impact on us could be substantial and adversely affect our ability to produce and market oil and gas.

An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flow from operations.

Our oil and gas is priced in the local markets where it is produced based on local or regional supply and demand factors. The prices we receive for all of our oil and gas are lower than the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Additionally, insufficient pipeline capacity, lack of demand in any given operating area or other factors may cause the differential to increase in a particular area compared with other producing areas. For example, production increases from competing Canadian and Rocky Mountain producers, combined with limited refining and pipeline capacity in the Rocky Mountain area, have gradually widened differentials in this area.

During 2008, differentials averaged $7.07 per Bbl of oil and $1.30 per Mcf of gas. Approximately 39% of our production during 2008 was from our Rocky Mountain and Mid-Continent properties. Historically, these regions have experienced wider differentials than our Permian Basin and Gulf Coast properties. As the percentage of our production from the Rocky Mountain and Mid-Continent regions increases, we expect that our price differentials will also increase. Increases in the differential between the benchmark prices for oil and gas and the wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

The Partnership's derivative contract activities could result in financial losses or could reduce our cash flow.

To achieve more predictable cash flow and reduce our exposure to adverse fluctuations in the prices of oil and gas and to comply with the requirements under the Partnership's credit facility, we have and expect to continue to enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production that could result in both realized and unrealized derivative contract losses. The Partnership has entered into NYMEX-based fixed price commodity swap

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arrangements on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011. The extent of our commodity price exposure is related largely to the effectiveness and scope of our commodity price derivative contract activities. For example, the prices utilized in our derivative instruments are NYMEX-based, which may differ significantly from the actual prices we receive for oil and gas which are based on the local markets where oil and gas are produced. The prices that we receive for our oil and gas production are lower than the relevant benchmark prices that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential. As a result, our cash flow could be affected if the basis differentials widen more than we anticipate. For more information see ''—An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flow from operations''. We currently do not have any basis differential hedging arrangements in place. Our cash flow could also be affected based upon the levels of our production. If production is higher than we estimate, we will have greater commodity price exposure than we intended. If production is lower than the nominal amount that is subject to our hedging arrangements, we may be forced to satisfy all or a portion of our hedging arrangements without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction in cash flows.

If the prices at which the Partnership has hedged its oil and gas production are less than current market prices, its ability to maintain or increase cash distributions could be adversely affected.

The Partnership has entered into NYMEX-based fixed price commodity swap arrangements on approximately 85% of its estimated oil and gas production from its estimated net proved developed producing reserves through December 31, 2011. The volume weighted average prices at which the Partnership has hedged this production are $84.23 per barrel of oil and $8.27 per MMbtu of gas. The hedged prices of oil and gas were greater than NYMEX future prices on December 31, 2008 of $44.60 per barrel of oil and $5.62 per Mcf of gas. When the Partnership's derivative contract prices are at higher than market prices, the Partnership will incur realized and unrealized gains on its derivative contracts and when contract prices are lower than market prices, the Partnership will incur realized and unrealized losses. For the year ended December 31, 2008 the Partnership recognized a realized loss on oil and gas derivative contracts of $9.3 million and an unrealized gain of $40.5 million. The realized loss resulted in a decrease in cash flow from operations of the Partnership as well as negatively impacting cash available for distribution by the Partnership. The Partnership expects to continue to enter into similar hedging arrangements in the future to reduce its cash flow volatility.

The following table sets forth the Partnership's oil and gas derivative contract position at December 31, 2008:

Period Covered	Product	Volume (Production per day)	Weighted Average Fixed Price
Year 2009	Gas	10,595 Mmbtu	$ 8.45
Year 2009	Oil	1,000 Bbl	$ 83.80
Year 2010	Gas	9,130 Mmbtu	$ 8.22
Year 2010	Oil	895 Bbl	$ 83.26
Year 2011	Gas	8,010 Mmbtu	$ 8.10
Year 2011	Oil	810 Bbl	$ 86.45

We cannot assure you that the derivative contracts that we have entered into, or will enter into, will adequately protect us from financial loss in the future due to circumstances such as:

- highly volatile oil and gas prices;

- our production being less than expected; or
- a counterparty to one of our hedging transactions defaulting on its contractual obligations.

Lower oil and gas prices increase the risk of ceiling limitation write downs.

We use the full cost method to account for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a “ceiling limit” which is based upon the present

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value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and earnings. The risk that we will be required to write-down the carrying value of oil and gas properties increases when oil and gas prices are low. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

At December 31, 2008, our net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves by $116.4 million resulting in a write-down of $116.4 million. We cannot assure you that we will not experience additional ceiling limitation writedowns in the future.

Use of our net operating loss carryforwards may be limited.

At December 31, 2008, we had, subject to the limitation discussed below, $194.4 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2028 if not utilized. In addition, as to a portion of the U.S. net operating loss carryforwards, the amount of such carryforwards that we can use annually is limited under U.S. tax law. Moreover, uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, we have established a valuation allowance of $66.9 million for deferred tax assets at December 31, 2006, $47.2 million at December 31, 2007 and $60.8 million at December 31, 2008.

We depend on our Chairman, President and CEO and the loss of his services could have an adverse effect on our operations.

We depend to a large extent on Robert L. G. Watson, our Chairman of the Board, President and Chief Executive Officer, for our management and business and financial contacts. Mr. Watson may terminate his employment agreement with us at any time on 30 days notice, but, if he terminates without cause, he would not be entitled to the severance benefits provided under the terms of that agreement. Mr. Watson is not precluded from working for, with or on behalf of a competitor upon termination of his employment with us. If Mr. Watson were no longer able or willing to act as our Chairman, the loss of his services could have an adverse effect on our operations. In addition, in connection with the initial public offering by our previously wholly-owned subsidiary, Grey Wolf Exploration Inc., we, Grey Wolf and Mr. Watson agreed that Mr. Watson would continue to serve as our Chief Executive Officer and President and as the Chief Executive Officer for Grey Wolf, with Mr. Watson devoting two-thirds of his time to his positions and duties with us and one-third of his time to his position and duties with Grey Wolf. In consideration for receiving Mr. Watson's services, Grey Wolf makes an annual payment to Abraxas of US$100,000 and reimburses Abraxas for Mr. Watson's expenses incurred in connection with providing such services.

Risks Related to Abraxas' Ownership of General Partner Units and Common Units of the Partnership

The Partnership's inability to refinance its obligations under the Subordinated Credit Agreement would have a material adverse impact on the liquidity, financial position and capital resources of Abraxas and the Partnership.

The Partnership's subordinated credit agreement matures on July 1, 2009. The Partnership intends to refinance this obligation prior to its scheduled maturity; however there can be no assurance that the Partnership will be successful in this effort. In addition, under the Partnership's subordinated credit agreement, an event of default would occur if the Partnership fails to receive $20.0 million of proceeds from an equity issuance on or before April 30, 2009. Abraxas Energy is currently in discussions with Société Générale to amend the existing Senior Secured Credit Facility and/or the Subordinated Credit Agreement in the event the IPO is not completed by April 30, 2009. The Partnership has also entered into discussions with other lending institutions to re-finance the $40 million currently outstanding on the Subordinated Credit Agreement. While the Company believes that there are options to this short term maturity requirement, there are no guarantees that any of these options will be successfully implemented. If additional funds are obtained by issuing equity securities, the Partnership's existing unitholders, including Abraxas, would be diluted and the distributions Abraxas receives from the Partnership could decrease. To the extent that the Partnership is unable to refinance theindebtedness under the subordinated credit agreement, consummate an issuance of additional equity securities or obtain additional

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financing, the Partnership may be required to sell assets and reduce capital expenditures, including distributions to Abraxas in order to avoid an event of default. We cannot assure you that the Partnership will be able to refinance the indebtedness under the Subordinated Credit Agreement, sell assets, or obtain additional financing on terms acceptable to it, if at all. If an event of default were to occur under the Subordinated Credit Agreement, an event of default would also occur under the Partnership's Credit Facility. Upon an event of default, the Partnership's lenders could foreclose on the Partnership's assets and exercise other customary remedies, all of which would leave a material adverse effect on the Partnership and Abraxas. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Long-Term Indebtedness Critical Accounting Policies – Amended and Restated Partnership Credit Facility."

The Partnership may not have sufficient cash flow from operations to pay the quarterly distributions on the general partner units and common units following establishment of cash reserves and payment of fees and expenses.

Under the terms of the Partnership's partnership agreement, the amount of cash otherwise available for distribution will be reduced by the Partnership's operating expenses and the amount of any cash reserve amounts that its general partner establishes to provide for future operations, future capital expenditures, future debt service requirements and future cash distributions to its unitholders, including Abraxas. The Partnership has informed Abraxas that the Partnership intends to reserve a substantial portion of its cash generated from operations to develop its oil and gas properties and to acquire additional oil and gas properties in order to maintain and grow the Partnership's level of oil and gas reserves.

The amount of cash the Partnership actually generates will depend upon numerous factors related to its business that may be beyond its control, including among other things:

- the amount of oil and gas it produces;
- price of oil and gas;
- continued drilling and development of oil and gas wells;
- the level of the Partnership's operating costs, including reimbursement of expenses to its general partner;
- prevailing economic conditions; and
- government regulation and taxation.

In addition, the actual amount of cash that the Partnership will have available for distribution will depend on other factors, including:

- the level of its capital expenditures;
- its ability to make borrowings under its credit facility to pay distributions;
- sources of cash used to fund acquisitions;
- debt service requirements and restrictions on distributions contained in its credit facility or future debt agreements;
- fluctuations in its working capital needs;

- general and administrative expenses;
- cash settlement of hedging positions;
- timing and collectability of receivables; and
- the amount of cash reserves, which the Partnership expects to be substantial, established by its general partner for the proper conduct of its business.

The Partnership is unlikely to be able to sustain its expected level of distributions without making accretive acquisitions or capital expenditures that maintain or grow its asset base. If the Partnership does not set aside sufficient cash reserves or make sufficient cash expenditures to maintain its asset base, it will be unable to pay distributions at the expected level from cash generated from operations and would likely reduce distributions.

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The Partnership is unlikely to be able to sustain its expected level of distributions without making accretive acquisitions or capital expenditures that maintain or grow its asset base. The Partnership will need to make capital expenditures to maintain and grow its asset base, which will reduce cash available for distributions. Because the timing and amount of these capital expenditures fluctuate each quarter, the Partnership expects to reserve substantial amounts of cash each quarter to finance these expenditures over time. The Partnership may use the reserved cash to reduce indebtedness until it makes the capital expenditures. Over a longer period of time, if the Partnership does not set aside sufficient cash reserves or make sufficient expenditures to maintain its asset base, it may be unable to pay distributions at the expected level from cash generated from operations and would therefore expect to reduce cash distributions. Under the terms of the Partnership Credit Agreement, the Partnership capital expenditures are limited to $12.5 million until the Subordinated Credit Agreement has been terminated. If the Partnership does not make sufficient growth capital expenditures, it may be unable to sustain its business operations and therefore will be unable to maintain its proposed or current level of distributions and its business, financial condition and results of operations would be adversely affected.

To fund its capital expenditures, the Partnership will be required to use cash generated from operations, additional borrowings or the issuance of additional partnership interests, or some combination thereof.

Use of cash generated from operations by the Partnership will reduce cash available for distribution to Abraxas as a unitholder. The Partnership's ability to borrow from its credit facility or to obtain additional bank financing or to access the capital markets for future equity or debt offerings may be limited by its financial condition at the time of any such borrowing, financing or offering and the covenants in its then-existing debt agreements, as well as by adverse market conditions resulting from, among other things, general economic conditions, operations and contingencies and uncertainties that are beyond the Partnership's control. The Partnership's failure to obtain the funds for necessary future capital expenditures could have a material adverse effect on its business, results of operations, financial condition and ability to pay distributions. Even if the Partnership is successful in obtaining the necessary funds, the terms of such financings could limit its ability to pay distributions to unitholders, including Abraxas. In addition, incurring additional debt may significantly increase the Partnership's interest expense and financial leverage, and issuing additional partnership interests may result in significant unitholder dilution thereby increasing the aggregate amount of cash required to maintain the then-current distribution rate, which could have a material adverse effect on the Partnership's ability to pay distributions at the then-current distribution rate.

The Partnership intends to make acquisitions of oil and gas properties to grow its asset base. Properties that the Partnership acquires may not produce as projected and it may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could adversely affect its cash available for distribution.

Part of the Partnership's business strategy is to make accretive acquisitions of oil and gas properties. Any future acquisition will require an assessment of recoverable reserves, title, future commodity prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Ordinarily, review efforts are focused on the higher-valued properties and are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed due diligence review may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations and the Partnership's ability to make cash distributions to its unitholders, including Abraxas.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the future prices of oil and gas or the future operating or development costs of properties acquired;

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- incorrect estimates of the oil and gas reserves attributable to a property acquired;
- unpredictable production profiles and decline rates of properties acquired;
- an inability to integrate successfully the properties acquired;
- the assumption of liabilities;
- limitations on rights to be indemnified by the seller;
- the diversion of management's attention from other business concerns; and
- losses of key operational employees at the acquired properties.

The Partnership’s ability to use hedging arrangements to protect it from future oil and gas price declines will be dependent upon oil and gas prices at the time it enters into these hedging arrangements and its future levels of hedging, and as a result of its future net cash flow may be more sensitive to commodity price changes.

The Partnership has currently hedged a significant portion of its estimated oil and gas production from its net proved developed producing reserves with NYMEX-based fixed price commodity swaps. As the Partnership’s derivative contracts expire, more of its future production will be sold at market prices unless it enters into further hedging arrangements. The Partnership’s commodity price hedging strategy and future hedging transactions will be determined at the discretion of its general partner, which is not under any future obligation to hedge a specific portion of its production. The prices at which the Partnership hedges its production in the future will be dependent upon commodity prices at the time it enters into these arrangements, which may be substantially higher or lower than current oil and gas prices. Accordingly, the Partnership’s commodity price hedging strategy may not protect it from significant declines in oil and gas prices received for its future production. Conversely, the Partnership’s commodity price hedging strategy has limited and may in the future limit its ability to realize increased cash flow from commodity price increases. It is also possible that a substantially larger percentage of the Partnership’s future production will not be hedged in the next few years, which would result in its oil and gas revenues becoming more sensitive to commodity price changes.

There may be conflicts of interest between Abraxas and the Partnership which could be detrimental to Abraxas.

Abraxas owns and controls the general partner of the Partnership and some of Abraxas’ directors and officers are directors and executive officers of the Partnership. Conflicts of interest exist and may arise between Abraxas and the Partnership. For example, the Partnership could acquire, develop or dispose of producing properties without any obligation to offer Abraxas the opportunity to purchase or develop any of the assets. In addition, it is currently anticipated that the executive officers of the general partner, who are officers of Abraxas, will devote between 30% and 60% of their time to the Partnership’s business.

The general partner of the Partnership, which is wholly- owned by Abraxas, may be removed as general partner with the consent of unitholders owning at least 662/3% of the common units, including units beneficially owned by Abraxas.

Holders of the common units of the Partnership are currently unable to remove the general partner without its consent because Abraxas beneficially owns sufficient units to be able to prevent the removal of the general partner. The vote of the holders of at least 66 2/3% of all outstanding common units voting together as a single class is required to remove the general partner. If Abraxas' beneficial ownership decreases below 33 1/3%, its subsidiary could be removed as the general partner which would result in Abraxas no longer controlling the business of the Partnership.

Risks Related to Our Industry

Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows, profitability and growth.

Our revenue, cash flows, profitability and future rate of growth depend substantially upon prevailing prices for oil and gas. Gas prices affect us more than oil prices because 65% of our production and 72% of reserves were gas at December 31, 2008. Prices also affect the amount of cash flow available for

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capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also make it uneconomical for us to increase or even continue current production levels of oil and gas.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and gas, market uncertainty and a variety of other factors beyond our control, including:

- changes in foreign and domestic supply and demand for oil and gas;
- political stability and economic conditions in oil producing countries, particularly in the Middle East;
- general economic conditions;
- domestic and foreign governmental regulation; and
- the price and availability of alternative fuel sources.

The current global recession has had a significant impact on commodity prices and our operations. If commodity prices remain depressed our revenues, profitability and cash flow from operations may decrease which could cause us to alter our business plans, including reducing our drilling activities.

Estimates of our proved reserves and future net revenue are inherently imprecise.

The process of estimating oil and gas reserves is complex involving decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

The estimates of our reserves are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of oil and gas reserves, future net revenue from proved reserves and the PV-10 thereof for our oil and gas properties are based on the assumption that future oil and gas prices remain the same as oil and gas prices at December 31, 2008. The sales prices as of such date used for purposes of such estimates were $4.77 per Mcf of gas and $41.84 per Bbl of oil. This compares with $6.33 per Mcf of gas and $87.30 per Bbl of oil as of December 31, 2007. These estimates also assume that Abraxas and the Partnership will make future capital expenditures of approximately $134.1 million in the aggregate primarily from 2009 through 2014, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. In addition, approximately 46% of our total estimated proved reserves as of December 31, 2008 were undeveloped. By their nature, estimates of undeveloped reserves are less certain than proved developed reserves. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth in this report.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

As required by SEC regulations, we base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of the estimate. However, actual future net cash flows from our properties will be affected by factors such as:

- supply of and demand for oil and gas;
- actual prices we receive for oil and gas;
- our actual operating costs;
- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and

- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flow, which is required by the SEC, 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 oil and gas industry in general. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our operations are subject to the numerous risks of oil and gas drilling and production activities.

Our oil and gas drilling and production activities are subject to numerous risks, many of which are beyond our control. These risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, ruptures and discharges of toxic gases. In addition, title problems, weather conditions and mechanical difficulties or shortages or delays in delivery of drilling rigs and other equipment could negatively affect our operations. If any of these or other similar industry operating risks occur, we could have substantial losses. Substantial losses also may result from injury or loss of life, severe damage to or destruction of property, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

We operate in a highly competitive industry which may adversely affect our operations.

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of oil and gas operations. We must compete for such resources with both major oil and gas companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our operations in the immediate future, we cannot assure you that such materials and resources will be available to us.

The unavailability or high cost of drilling rigs, equipment, supplies, insurance, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, insurance or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. As a result of increasing levels of exploration and production in response to strong prices of oil and gas, the demand for oilfield services has risen and the costs of these services are increasing.

Our oil and gas operations are subject to various Federal, state and local regulations that materially affect our operations.

Matters regulated include permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. Federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances and materials produced or used in connection with oil and gas operations. To date, our expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant. We believe that we are in substantial compliance with all applicable laws and regulations. However, the

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requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Risks Related to the Common Stock

Future issuance of additional shares of common stock could cause dilution of ownership interests and adversely affect the stock price.

Abraxas is currently authorized to issue 200,000,000 shares of common stock with such rights as determined by our board of directors. Abraxas may in the future issue its previously authorized and unissued securities, resulting in the dilution of the ownership interests of current stockholders. In addition, under the terms of the Exchange and Registration Rights Agreement entered into in connection with the transactions completed in May 2007 and amended in October 2008, Abraxas may be required to issue additional shares of common stock. Under the terms of this amended agreement, in the event that the Partnership has not consummated its initial public offering by April 30, 2009, which we refer to as the Trigger Date, the investors will have the right to convert their common units obtained in the private placement offering into shares of common stock. Each common unit will be convertible into a number of shares of common stock equal to $16.66 divided by the volume weighted average price of the common stock for the ten (10) business day period immediately prior to the first business day following the Trigger Date times 0.9. If stockholder approval is required for such issuance, Abraxas has agreed to call a special meeting of the stockholders within 60 days of April 30, 2009, which we refer to as the Exchange Filing Date, and the executive officers and directors of Abraxas have agreed to vote the shares of common stock then held by them in favor of such issuance. Under this agreement, Abraxas also agreed within 30 days of the Trigger Date, to prepare and file with the Securities and Exchange Commission a registration statement, which we refer to as the Exchange Registration Statement, to enable the resale of the common stock, which we refer to as the Exchange Shares, by the investors or their transferees from time to time over any national stock exchange on which the common stock is then traded, or in privately-negotiated transactions. If the Exchange Registration Statement is not declared effective by the 120th day following the Trigger Date (which period would be extended to the 180th day following the Trigger Date under certain circumstances), then in addition to any other rights the investors may have under the Exchange and Registration Rights Agreement or under applicable law, Abraxas is required to pay an amount in cash as liquidated damages and not as a penalty, equal to 1.0% of the product of $3.83 times the number of Exchange Shares then held by such investor for each 30-day period until the Exchange Registration Statement is declared effective. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of the common stock. Abraxas may also issue additional shares of common stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of the common stock.

Abraxas does not pay dividends on common stock.

Abraxas has never paid a cash dividend on its common stock and the terms of Abraxas' credit facility prohibit its ability to pay dividends on Abraxas' common stock.

Shares eligible for future sale may depress our stock price.

At February 13, 2009, Abraxas had 49,621,711 shares of common stock outstanding of which 4,334,568 shares were held by affiliates and, in addition, 2,398,778 shares of common stock were subject to outstanding options granted under certain stock option plans (of which 1,965,987 shares were vested at February 13, 2009).

All of the shares of common stock held by affiliates are restricted or controlled securities under Rule 144 promulgated under the Securities Act of 1933, as amended (the "Securities Act"). The shares of the common stock issuable upon exercise of the stock options have been registered under the Securities Act. Sales of shares of common stock under Rule 144 or another exemption under the Securities Act or pursuant to a registration statement could have a material adverse effect on the price of the common stock and could impair our ability to raise additional capital through the sale of equity securities.

The price of Abraxas common stock has been volatile and could continue to fluctuate substantially.

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The Abraxas common stock is traded on the NASDAQ Stock Market. The market price of the common stock has been volatile and could fluctuate substantially based on a variety of factors, including the following:

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the industry;
- market conditions; and
- analysts' estimates and other events in the oil and gas oil industry.

Abraxas may issue shares of preferred stock with greater rights than the common stock.

Subject to the rules of the NASDAQ Stock Market, Abraxas' articles of incorporation authorize its board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of the common stock. Any preferred stock that is issued may rank ahead of the common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than the common stock.

Anti takeover provisions could make a third party acquisition of Abraxas difficult.

Abraxas' articles of incorporation and bylaws provide for a classified board of directors, with each member serving a three-year term, and eliminate the ability of stockholders to call special meetings or take action by written consent. Each of the provisions in the articles of incorporation and bylaws could make it more difficult for a third party to acquire Abraxas without the approval of its board. In addition, the Nevada corporate statute also contains certain provisions that could make an acquisition by a third party more difficult.

An active market may not continue for the common stock.

The Abraxas common stock is quoted on the NASDAQ Stock Market. While there are currently three market makers in the common stock, these market makers are not obligated to continue to make a market in the common stock. In this event, the liquidity of the common stock could be adversely impacted and a stockholder could have difficulty obtaining accurate stock quotes.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Primary Operating Areas

The following table sets forth certain information relating to our properties as of December 31, 2008.

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	Producing Wells	Average Working Interest	Estimated Net Proved Reserves (MMBOE)	Year ended December 31, 2008 Net Production (MBOE)
Rocky Mountain	894	12.4%	4,935.7	404.2
Mid-Continent	602	17.1%	3,050.4	435.8
Permian Basin	236	68.0%	10,413.6	545.0
Gulf Coast	79	69.2%	6,716.0	222.0
Total	1,811	23.7%	25,115.7	1,607.0

Rocky Mountain

Our Rocky Mountain properties consist of the following:

- Northern Rockies—Our properties in the Northern Rockies are located in the Williston Basin of North Dakota, South Dakota and Montana and consist of wells that produce oil from Paleozoic-aged carbonate reservoirs from the Madison formation at 8,000 feet down to the Red River formation at 12,000 feet, including the Bakken at 9,000 feet.

- Southern Rockies—Our properties in the Southern Rockies are located in the Green River, Powder River and Uinta Basins of Wyoming, Colorado and Utah and consist of wells that produce oil from Cretaceous-aged fractured shales in the Mowry and Niobrara formation and oil and gas from Cretaceous-aged sandstones in the Turner, Muddy and Frontier formations. Well depths range from 7,000 feet down to 10,000 feet.

Mid-Continent

Our Mid-Continent properties consist of the following:

- Arkoma Basin—Our properties in the Arkoma Basin are located in Oklahoma and Arkansas and consist of wells that mainly produce gas from Hartshorne coals at 3,000 feet.

- Anadarko Basin—Our properties in the Anadarko Basin are located in Oklahoma and the Texas Panhandle and consist of wells that mainly produce gas from Pennsylvanian-aged sandstones (Atoka/Morrow) from depths of up to 18,000 feet.

- ARK-LA-TEX—Our properties in the ARK-LA-TEX region principally produce from the East Texas/North Louisiana Basins and includes wells that produce oil and gas from various formations.

Permian Basin

Our Permian Basin properties consist of the following:

- ROC Complex—Our properties in the ROC Complex are located in Pecos, Reeves and Ward Counties and consist of wells that produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet.

- Oates SW—Our properties in the Oates SW area are located in Pecos County and consist of wells that produce gas from the Devonian formation at a depth of approximately 13,500 feet.

- Eastern Shelf – Our properties in the Eastern Shelf are predominately located in Coke, Scurry and Mitchell Counties and consist of wells that produce oil and gas from the Strawn Reef formation at 5,000 to 6,000 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet Wilcox – Our properties in the Wilcox are located in Goliad, Bee and Karnes Counties and

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consist of wells that produce gas from various sands in the Wilcox formation at depths ranging from8,000to 11,000 feet.

Gulf Coast

Our Gulf Coast properties consist of the following:

- Edwards—Our properties fields in the Edwards trend are located in Dewitt and Lavaca counties and consist of wells which produce gas from the Edwards formation at a depth of approximately 13,500 feet.

- Portilla—The Portilla field – located in San Patricio County, was discovered in 1950 by The Superior Oil Company, predecessor to Mobil Oil Corporation, and consists of wells that produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet.

- Wilcox – Our properties in the Wilcox are located in Goliad, Bee and Karnes Counties and consist of wells that produce gas from various sands in the Wilcox formation at depths ranging from 8,000 to 11,000 feet.

Exploratory and Developmental Acreage

Our principal oil and gas properties consist of producing and non-producing oil and gas leases, including reserves of oil and gas in place. The following table indicates our interest in developed and undeveloped acreage and fee mineral acreage as of December 31, 2008

	Developed Acreage (1)		Undeveloped Acreage(2)		Fee Mineral Acreage (3)		Total
	Gross Acres(4)	Net Acres (5)	Gross Acres(4)	Net Acres (5)	Gross Acres(4)	Net Acres (5)	Net Acres (6)
Rocky Mountain (7)	63,225	32,903	92,317	64,376	-	-	97,279
Mid-Continent (8)	85,812	21,949	1,957	988	-	-	22,937
Permian Basin (9)	24,574	17,197	10,882	8,768	12,007	5,272	31,237
Gulf Coast (10)	11,699	6,675	4,837	2,013	-	-	8,688
Total	185,310	78,724	109,993	76,145	12,007	5,272	160,141

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(1) Developed acreage consists of leased acres spaced or assignable to productive wells.

(2) Undeveloped acreage is considered to be those leased acres 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.

(3) Fee mineral acreage represents fee simple absolute ownership of the mineral estate or fraction thereof.

(4) Gross acres refers to the number of acres in which we own a working interest.

(5) Net acres represents the number of acres attributable to an owner's proportionate working interest (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

(6) Includes 3,981 acres that are included in developed and undeveloped gross acres.

(7) The following shows the amount of acreage owned by each of Abraxas and the Partnership in Rocky Mountain region as of December 31, 2008:

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	Developed Acreage		Undeveloped Acreage		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres
Abraxas	6,814	5,401	31,977	28,598	33,999
Partnership	56,411	27,502	60,340	35,778	63,280
Total	63,225	32,903	92,317	64,376	97,279

(8) The following shows the amount of acreage owned by each of Abraxas and the Partnership in Mid-Continent region as of December 31, 2008:

	Developed Acreage		Undeveloped Acreage		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres
Abraxas	679	16	-	-	16
Partnership	85,133	21,933	1,957	988	22,921
Total	85,812	21,949	1,957	988	22,937

(9) The following shows the amount of acreage owned by each of Abraxas and the Partnership in Permian Basin region as of December 31, 2008:

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres(6)	Net Acres	Total Net Acres
Abraxas	14,793	11,323	9,456	7,981	12,007	5,272	24,575
Partnership	12,425	8,388	1,766	1,127	-		