ABRAXAS PETROLEUM CORP
Form 10-K/A
November 14, 2007

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A Number 3

(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, 2006

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

COMMISSION FILE NUMBER 001-16701

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

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

500 N. Loop 1604 East, Suite 100
San Antonio, Texas 78232
(Address of principal executive offices)

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

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	American Stock Exchange

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 [X]

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 [X]

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 [X] No [ ]

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

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

Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer [ ]

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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, 2006, the aggregate market value of the common stock held by non-affiliates of the registrant was $167,042,727 based on the closing sale price as reported on the American Stock Exchange.

As of March 9, 2007, there were 42,762,466 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2007Annual Meeting of Shareholders to be held on May 23, 2007.	Part III

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In connection with the filing of a Registration Statement on Form S-1 by Abraxas Energy Partners, L.P. Our reserve estimates at December 31, 2006 included approximately 12 Bcf of reserves classified as proved undeveloped reserves in our reserve report prepared by independent third-party engineers as of December 31, 2006. The subject reserves, predominately located in West Texas, are scheduled to be produced from deeper formations in wellbores that are currently producing in commercial quantities from a shallower formation. We scheduled the redeepenings to develop such reserves from the deeper formation beginning at the time the shallower formation is expected to be depleted, which according to our reserve report would not occur within the next five years.

In connection with the filing of the Registration Statement on Form S-1 of Abraxas Energy, we concluded that we should reclassify these reserves and remove them from the proved undeveloped category as previously reported in our 2006 Form 10-K because the future redeepenings are not scheduled to be performed for many years in the future and require significant additional capital such as for deepening wells are subject to greater uncertainties such as depletion from offsetting wells, changes in management, greater geological risks, changes in the company's strategy or focus and other factors. We believe that these greater uncertainties suggest that these volumes should remain as unproved until they are more reasonably certain of being developed. These reserves represented approximately 12% of our proved reserves at December 31, 2006 but only approximately 3% of our PV-10 at such date.

This amendment is being filed to reflect the restatement of the Company's consolidated financial statements to reflect the impact of the changes discussed above. See Note 14 to the consolidated financial statements and other information related to such restated financial statements. Except for Items 1, 1A and 2 of Part I, Items 6, 7 and 8 of Part II and Item 15 of Part IV, no other information included in the original report on Form 10-K filed on March 14, 2007, as amended by Form 10-K/A Number 1 as filed on April 30, 2007, as amended by Form 10-K A/ Number 2 as filed on August 24, 2007, is amended by this Form 10-K/A Number 3. For convenience, we have repeated our original Form 10-K filed on March 14, 2007 in its entirety.

This amendment does not reflect events occurring after the filing of the Original Form 10-K, and does not modify or update the disclosures therein in any way other than as required to reflect the matters described above. Such events include among others, the events described in our quarterly report on Form 10-Q for the quarter ended March 31, 2007, as amended, the quarterly report on Form 10-Q for the quarter and year-to-date period ended June 30, 2007, as amended by Form 10-Q/A Number 1 filed on August 24, 2007, as amended, the quarterly report on Form 10-Q for the quarter and year-to-date period ended September 30, 2007, as amended and the events described in our current reports on Form 8-K filed after the filing of the Original Form 10-K. -

ABRAXAS PETROLEUM CORPORATION

FORM 10-K/A Number 3

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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", "seek", "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 high debt level;
- our success in development and exploration activities;
- our ability to make planned capital expenditures;
- declines in our production of natural gas and crude oil;
- prices for natural gas and crude oil;
- 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

As part of a series of restructuring transactions approved in 2004, we adopted a plan to dispose of our operations and interest in Grey Wolf Exploration Inc., a wholly-owned Canadian subsidiary of Abraxas Petroleum Corporation. In February 2005, Grey Wolf closed on an initial public offering resulting in our substantial divestiture of our capital stock in Grey Wolf. As a result of the disposal of Grey Wolf, the results of operations of Grey Wolf are reflected in our Financial Statements and in this document as "Discontinued Operations" and our remaining operations are referred to in our Financial Statements and in this document as "Continuing Operations" or "Continued Operations." Unless otherwise noted, all disclosures are for continuing operations. See Note 3 to the financial statements in Item 8.

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 natural gas. MMcf is used to designate one million cubic feet of natural gas and Bcf refers to one billion cubic feet of natural gas. Mcfe means thousands of cubic feet of natural gas equivalents, using a conversion ratio of one barrel of crude oil to six Mcf of natural gas. MMcfe means millions of cubic feet of natural gas equivalents and Bcfe means billions of cubic feet of natural gas equivalents. MMBtu means million British Thermal Units. The term Bbl means one barrel of crude oil or natural gas liquids and MBbls is used to designate one thousand barrels of crude oil or natural gas liquids.

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General

We are an independent energy company primarily engaged in the development and production of natural gas and crude oil. 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 substantial inventory of development opportunities, which provide a basis for significant production and reserve increases. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation.

Our core areas of operation are in south and west Texas and east central Wyoming. Our primary properties are located in mature fields that exhibit relatively long-lived production, with a reserve to production index of 12.8 years (5.8 years for our proved developed reserves), as of December 31, 2006. At December 31, 2006, we owned interests in 101,815 gross acres (87,554 net acres) applicable to our continuing operations, and operated properties accounting for approximately 96% of our PV-10, affording us substantial control over the timing and incurrence of operating and capital expenditures. At December 31, 2006, estimated total proved reserves were 86.9 Bcfe with an aggregate PV-10 of $157 million. During 2006, we participated in the drilling of 5 gross (4.2 net) wells with 4 gross (3.2 net) wells being successful. Total capital expenditures for

2006 were approximately $26 million, of which 35% was spent on 2 wells in the SW Oates Field of West Texas which were still in progress at year-end. Overall, during 2006 our proved reserves declined by approximately 2.1 Bcfe. Property sales of 1.8 Bcfe and production of 7.7 Bcfe further reduced our proved reserves.

We believe that our high quality asset base, high degree of operational control and large inventory of drilling projects positions us for future growth. Our properties are concentrated in locations that facilitate substantial economies of scale in drilling and production operations and efficient reservoir management practices. In addition, we have 51 proved undeveloped projects and have identified over 500 drilling and recompletion opportunities on our existing acreage, the successful development of which we believe could significantly increase our daily production and proved reserves. We have approved a capital budget ranging from $27.0 to $44.0 million for 2007, (the final amount of which will depend upon our cash flow from operations which, in turn, is dependent upon our production volumes and commodity prices) which will be used primarily for the development of our current properties as well as to drill and complete the wells that were in progress at the end of 2006. This drilling program will be funded by cash flow from operations, availability under our revolving credit facility and if necessary, equity financing. Our ability to complete this drilling program may also be limited due to the lack of availability of drilling rigs and other equipment.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices of, and demand for, natural gas and crude oil. Historically, the markets for natural gas and crude oil have been volatile and are likely to continue to be volatile in the future. The prices we receive for our natural gas and crude oil 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 crude oil-producing and natural gas-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices of natural gas and crude oil 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 natural gas and crude oil, and particularly volatility of prices for natural gas and crude oil, 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 natural gas and crude oil prices on us. To help mitigate the impact of commodity price volatility, we hedge our production through the use of price floors. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - General - Commodity Prices and Hedging Activities" and

Note 12 of the notes to our consolidated financial statements for more information regarding our hedging activities.

Substantially all of our natural gas and crude oil is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2006, two purchasers accounted for approximately 49% of our natural gas and crude oil sales. We believe that there are numerous other companies available to purchase our natural gas and crude oil and that the loss of one or more of these purchasers would not materially affect our ability to sell natural gas and crude oil.

Regulation of Natural Gas and Crude Oil 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, crude oil and natural 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 crude oil, natural gas, condensate and NGLs were subject to significant federal regulation. At the present time, however, all sales of our crude oil, natural gas and condensate 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.

Natural Gas Regulation

Historically, the natural gas industry as a whole has been more heavily regulated than the crude oil or other liquid hydrocarbons market. Most regulations focused 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 gathering services, storage services, firm and interruptible transportation services, and standby sales and natural gas balancing services), and to adopt a new ratemaking methodology to determine appropriate rates for those services. To the extent the pipeline company or its sales affiliate markets natural 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 natural 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 natural gas. Our physical sales of natural 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 natural gas in the marketplace. FERC continues to review and modify its regulations regarding the transportation of natural gas. The 2005 Energy Policy Act recently authorized FERC to allow natural 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 natural gas storage service.

In recent years FERC also has pursued a number of important policy initiatives which could significantly affect the marketing of natural gas in the United States. Most of these initiatives are intended to enhance competition in natural 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 natural gas gathering companies that have been "spun-down" from an affiliated interstate natural 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 natural 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 natural gas through gathering facilities owned by others. Although FERC decisions create the potential for increasing the cost of shipping our natural 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 natural 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 natural 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 natural gas and crude oil 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 natural gas and crude oil properties have statutory provisions regulating the exploration for and production of natural gas and crude oil. These include provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells and provisions 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 natural gas and crude oil 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 natural gas and crude oil wells, generally prohibit the venting or flaring of natural 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 crude oil and natural 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, natural 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 natural 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 costs that are deductible transportation 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, or long-term storage fees. Further, the MMS has been engaged in a process of promulgating new rules and procedures for determining the value of crude oil produced from federal lands for purposes of calculating royalties owed to the government. The natural gas and crude oil industry as a whole has resisted the proposed rules under an assumption that royalty burdens will substantially increase. We cannot predict what, if any, effect any new rule will have 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 natural 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 natural gas and crude oil 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.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as "Superfund," and comparable state statutes impose strict, joint, and several liability 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 and for damages to natural resources, and it is common 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 our ordinary operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed. 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 crude oil cleanups. In addition, although RCRA regulations currently classify certain oilfield wastes which are uniquely associated with field operations as "non-hazardous," such exploration, development and production wastes could be reclassified by regulation as hazardous wastes thereby administratively making such wastes subject to more stringent handling and disposal requirements.

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 natural gas and crude oil. Although we 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 crude oil, such as us, to prepare and implement spill prevention, control and countermeasure plans and spill response plans relating to possible discharge of crude oil into surface waters. The federal Oil Pollution Act ("OPA") contains numerous requirements relating to prevention of, reporting of, and response to crude 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 crude 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 crude oil and natural gas operational wastes under three federal acts more fully discussed in the paragraphs that follow. The Resource Conservation and Recovery Act of 1976, as amended ("RCRA"), provides a framework for the safe disposal of discarded materials and the management of solid and hazardous wastes. The direct disposal of operational wastes into offshore waters is also limited under the authority of the Clean Water Act. When injected underground, crude oil and natural 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.

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 crude oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes crude oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

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

Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for crude 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 crude oil and natural gas production. The Safe Drinking Water Act of 1974, as amended establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In 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.

Air Pollution Control. The Clean Air Act and state air pollution laws adopted to fulfill its mandate provide a framework for national, state and local efforts to protect air quality. Our operations 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. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

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 crude oil and natural gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards established by the State of Texas.

Abandonment Costs. All of our crude oil and natural 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 natural gas and crude oil industry, we make only a cursory review of title to undeveloped natural gas and crude oil 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 natural gas and crude oil properties, some of which are subject to immaterial encumbrances, easements and restrictions. The natural gas and crude oil 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.

Competition

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of natural gas and crude oil are leasehold prospects under which natural gas and crude oil reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of natural gas and crude oil operations. We must compete for such resources with both major natural gas and crude oil 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 crude 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 March 9, 2007 we had 50 full-time employees in the United States, including two executive officers, three non-executive officers, one petroleum engineer, one geologist, five managers, one landman, eleven administrative and support personnel and 26 field personnel. Additionally, we retain contract gaugers on a month-to-month basis. We retain independent geological 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 have a highly leveraged capital structure, which limits our operating and financial flexibility.

We have a highly leveraged capital structure. At March 9, 2007, we had total indebtedness, including our floating rate senior secured notes due 2009, or notes, of approximately $127.3 million, all of which is secured indebtedness. We also had availability of $12.7 million under our $15.0 million senior secured revolving credit facility, all of which is also secured indebtedness.

Our highly leveraged capital structure will have several important affects on our future operations, including:

- a substantial amount of our cash flow from operations will be required to service our indebtedness, which will reduce the funds that would otherwise be available for operations, capital expenditures and expansion opportunities, including developing our properties;

- the covenants contained in our revolving credit facility require us to meet certain financial tests and comply with certain other restrictions, including limitations on capital expenditures. These restrictions, together with those in the indenture governing the notes, may limit our ability to undertake certain activities and respond to changes in our business and our industry;

- our debt level may impair our ability to obtain additional capital, through equity offerings or debt financings, for working capital, capital expenditures, or refinancing of indebtedness;

- our debt level makes us more vulnerable to economic downturns and adverse developments in our industry (especially declines in natural gas and crude oil prices) and the economy in general; and

- the notes and our revolving credit facility are subject to variable interest rates which makes us vulnerable to interest rate increases.

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

We are required to 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 equity securities and we expect to continue to do so in the future; however, we cannot assure you that we will have sufficient capital resources in the future to finance all of our capital expenditures.

Volatility in natural gas and crude oil prices, the timing of our drilling program and our drilling results will affect our cash flow from operations. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet our 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 our planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and our planned capital expenditures would, by necessity, be decreased.

The borrowing base under our revolving credit facility will be determined from time to time by our lenders, consistent with their customary natural gas and crude oil lending practices. Reductions in estimates of our natural gas and crude oil reserves could result in a reduction in our borrowing base, which would reduce the amount of financial resources available under our revolving credit facility 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 natural gas and crude oil 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 base decrease for any reason, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited. In addition, if the borrowing base under our revolving credit facility is reduced, we would be required to reduce our borrowings under our revolving credit facility so that such borrowings do not exceed the borrowing base. This could further reduce the cash available to us for capital spending and, if we did not have sufficient capital to reduce our borrowing level, could cause us to default under our revolving credit facility and the notes.

We have sold producing properties to provide us with liquidity and capital resources in the past, including during 2006, and may do so in the future. After any such sale, we would expect to utilize the proceeds to drill new wells. If we cannot replace the production lost from properties sold with production from new properties, our cash flow from operations will likely decrease which, in turn, would decrease the amount of cash available for debt service and 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 natural gas and crude oil 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 natural gas and crude oil 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. For example, in 2006, while we have had some success in pursuing these activities, we were not able to fully replace the production volumes lost from natural field declines and property sales. If our proved reserves continue to decline in the future, our production will also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our revolving credit facility will also decline. In addition, approximately 45% of our total estimated proved reserves at December 31, 2006 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.

A substantial portion of our production is currently concentrated in one well.

Approximately 29% of our production during 2006 was from a single well in west Texas. Like all natural gas wells, the rate of production from this well will decline over time and the reserves associated with this well will also decrease. If production from this well decreases, and if we are unable to reduce the percentage of our production represented by this well, it would have a material adverse effect on our revenues, cash flow from operations and financial condition. This well is subject to all of the risks typically associated with natural gas wells, including depletion and the risks described in "Risks Related to Our Industry - Our operations are subject to the numerous risks of natural gas and crude oil drilling and production activities."

We may not find any commercially productive natural gas or crude oil 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 natural gas and crude oil 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 45% of our total estimated proved reserves at December 31, 2006 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 natural gas and crude oil we produce decreases, our cash flow from operations will decrease.

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 interest.

Our revolving credit facility and the indenture governing the notes contain a number of significant covenants that, among other things, limit our ability to:

- o incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- o transfer or sell assets;
- o create liens on assets;
- o 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;
- o engage in transactions with affiliates;
- o guarantee other indebtedness;
- o make any change in the principal nature of our business;

- o prepay, redeem, purchase or otherwise acquire any of our or our restricted subsidiaries' indebtedness;
- o permit a change of control;
- o directly or indirectly make or acquire any investment;
- o cause a restricted subsidiary to issue or sell our capital

stock; and

- consolidate, merge or transfer all or substantially all of the consolidated assets of Abraxas and our restricted subsidiaries.

In addition, our revolving credit facility requires us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our 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 our inability to comply with the required financial ratios or financial condition tests could result in a default under our revolving credit facility and the notes. A default, if not cured or waived, could result in all of our indebtedness, including the notes, 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 to us.

The marketability of our production depends largely upon the availability, proximity and capacity of natural 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 natural gas and crude oil 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 natural gas and crude oil.

Hedging transactions have in the past and may in the future impact our cash flow from operations.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in natural gas and crude oil prices and to achieve more predictable cash flow. In 2005, we incurred a hedging loss of $592,000, resulting from the price floors we established. For the year ended December 31, 2004 and 2006, we recognized a gain from hedging activities of approximately $118,000 and $646,000 respectively. Currently, we believe our hedging arrangements, which are in the form of price floors, do not expose us to significant financial risk.

We cannot assure you that the hedging transactions 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 natural gas and crude oil prices;

- our production being less than expected; or

- a counterparty to one of our hedging transactions defaulting on its contractual obligations.

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

We use the full cost method to account for our natural gas and crude oil operations. Accordingly, we capitalize the cost to acquire, explore for and develop natural gas and crude oil properties. Under full cost accounting rules, the net capitalized cost of natural gas and crude oil properties may not exceed

a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10%. If net capitalized costs of natural gas and crude oil 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 natural gas and crude oil properties increases when natural gas and crude oil 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 natural gas and crude oil prices may have increased the ceiling applicable to the subsequent period.

We have incurred ceiling limitation write-downs in the past. We cannot assure you that we will not experience additional ceiling limitation write-downs in the future.

Use of our net operating loss carryforwards may be limited.

At December 31, 2006, we had, subject to the limitation discussed below, $192.7 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2026 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 for deferred tax assets at December 31, 2005 and 2006.

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 Our IndustryItem 1A.

Market conditions for natural gas and crude oil, and particularly volatility of prices for natural gas and crude oil, 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 natural gas and crude oil. Natural gas prices affect us more than crude oil prices because most of our production and reserves are natural gas. Prices also affect the amount of cash flow available for 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 natural gas and crude oil.

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

- changes in foreign and domestic supply and demand for natural gas and crude oil;

- 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.

In addition to decreasing our revenue and cash flow from operations, low or declining natural gas and crude oil prices could have additional material adverse effects on us, such as:

- reducing the overall volume of natural gas and crude oil that we can produce economically, thereby adversely affecting our revenue, profitability and cash flow and our ability to perform our obligations with respect to the notes;
- reducing our borrowing base under the credit facility; and
- impairing our borrowing capacity and our ability to obtain equity capital.

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

The process of estimating natural gas and crude oil 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, natural gas and crude oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil 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 natural gas and crude oil 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 natural gas and crude oil reserves, future net revenue from proved reserves and the PV-10 thereof for our natural gas and crude oil properties are based on the assumption that future natural gas and crude oil prices remain the same as natural gas and crude oil prices at December 31, 2006. The sales prices as of such date used for purposes of such estimates were $5.83 per Mcf of natural gas and $56.42 per Bbl of crude oil. This compares with $8.84 per Mcf of natural gas and $56.92 per Bbl of crude oil as of December 31, 2005. These estimates also assume that we will make future capital expenditures of approximately $73.4 million in the aggregate through 2026, with the majority expected to be incurred from 2007 to 2012, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. 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 revenues we disclose may not be the current market value of our estimated natural gas and crude oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the period of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the end of the year of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and crude oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with us or the natural gas and crude oil industry in general will affect the accuracy of the 10% discount factor.

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

Our natural gas and crude oil 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, natural 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 natural gas and crude oil are leasehold prospects under which natural gas and crude oil reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of natural gas and crude oil operations. We must compete for such resources with both major natural gas and crude oil 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 crude 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 natural gas and crude oil, the demand for oilfield services has risen and the costs of these services are increasing.

Our natural gas and crude oil 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 natural gas and crude oil, these agencies have restricted the rates of flow of natural gas and crude oil wells below actual production capacity. Federal, state and local laws regulate production, handling, storage, transportation and disposal of natural gas and crude oil, by-products from natural gas and crude oil and other substances and materials produced or used in connection with natural gas and crude oil 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 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

We do not pay dividends on common stock.

We have never paid a cash dividend on our common stock and the terms of the revolving credit facility and the indenture relating to the notes limit our ability to pay dividends on our common stock.

Shares eligible for future sale may depress our stock price.

At March 9, 2007, we had 42,769,284 shares of common stock outstanding of which 3,628,078 shares were held by affiliates and, in addition, 2,467,716 shares of common stock were subject to outstanding options granted under certain stock option plans (of which 1,908,116 shares were vested at March 9, 2007).

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 our common stock has been volatile and could continue to fluctuate substantially.

Our common stock is traded on The American Stock Exchange. The market price of our 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 natural gas and crude oil industry.

We may issue shares of preferred stock with greater rights than our common stock.

Subject to the rules of The American Stock Exchange, our articles of incorporation authorize our 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 our common stock. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than our common stock.

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

Our 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 our 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 develop for our common stock.

Our common stock is quoted on The American Stock Exchange. While there is currently one specialist in our common stock, this specialist is not obligated to continue to make a market in our common stock. In this event, the liquidity of our common stock could be adversely impacted and a stockholder could have difficulty obtaining accurate stock quotes.

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

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our current stockholders. We are currently authorized to issue 200,000,000 shares of common stock with such rights as determined by our board of directors. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our 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 our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Primary Operating Areas

Texas

Our operations are concentrated in south and west Texas with over 99% of the PV-10 of our natural gas and crude oil properties at December 31, 2006 located in those two regions. We operate 93% of our wells in Texas. During 2006, we drilled a total of 5 new wells (4.2 net) in Texas with an 80% success rate. This drilling, although somewhat successful did not fully replace the production volumes lost from natural field declines and property sales. During 2006, we sold natural gas properties with reserves of 1.8 Bcfe and produced 7.7 Bcfe.

Operations in south Texas are concentrated along the Edwards trend in DeWitt and Lavaca Counties, the Frio/Vicksburg trend in San Patricio County and the Wilcox trend in Bee, Karnes, Goliad and DeWitt Counties. In south Texas, we own an average 94% working interest in 41 wells with average production of 205 net Bbls of crude oil and 5,759 net Mcf of natural gas per day for the year ended December 31, 2006. As of December 31, 2006, we had estimated net proved reserves in south Texas of 29.9 Bcfe (89% natural gas) with a PV-10 of $59.1 million, 62% of which was attributable to proved developed reserves.

Our west Texas operations are concentrated along the deep Devonian/Montoya/Ellenburger formations and shallow Cherry Canyon sandstones in Ward County, the Sharon Ridge Clearfork Field in Scurry and Mitchell Counties and Devonian, Woodford and Wolfcamp formations in Pecos County. We drilled one well in west Texas which was brought onto production in August 2005 that accounted for approximately 29% of our production in 2006.

In west Texas, we own an average 75% working interest in 169 wells with average daily production of 298 net Bbls of crude oil and 12,090 net Mcf of natural gas per day for the year ended December 31, 2006. As of December 31, 2006, we had estimated net proved reserves in west Texas of 56.0 Bcfe (78% natural gas) with a PV-10 of $96.1 million, 50% of which was attributable to proved developed reserves.

In the Abraxas Cherry Canyon Field of Ward County, Texas, we have two wells currently being completed in the Bell and Cherry Canyon sands. In the Oates SW Field of Pecos County, Texas, we have two wells which began drilling in 2006 and are still in progress and one well that is currently awaiting a drilling rig to drill the horizontal lateral in the Devonian formation.

Wyoming

We currently hold 50,409 acres in the Powder River Basin in east central Wyoming. We have drilled and operate ten wells in Converse and Niobrara counties that were completed in the Muddy, Mowry, Turner, and Niobrara

formations. We own a 100% working interest in these wells that produced a combined average of 46 net barrels of crude oil per day in 2006. As of December 31, 2006, we had estimated net proved producing reserves in Wyoming of 169,633 barrels of crude oil with a PV-10 of $1.6 million.

During 2006, the wells that were drilled in late 2005 were fracture stimulated and brought onto production. In the Brooks Draw Field of Wyoming, we are currently in the process of permitting new horizontal Mowry Shale wells while monitoring industry activity in this new area. We plan to drill several more wells in Wyoming during 2007.

Exploratory and Developmental Acreage

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

	Developed Acreage (1)		Undeveloped Acreage (2)		Fee Mineral Acreage (3)	
	Gross Acres (4)	Net Acres (5)	Gross Acres (4)	Net Acres (5)	Gross Acres (6)	Net Acres
South Texas	4,687	4,258	3,496	3,256	-	-
West Texas	20,868	15,616	17,752	12,617	12,007	5,272
Wyoming	3,400	3,400	47,009	43,111	-	-
N. Dakota	-	-	80	24	-	-
Total	28,955	23,274	68,337	59,008	12,007	5,272

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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 natural gas and crude oil, 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 acres is equivalent to 160 net acres).

(6) Includes 7,484 acres that are included in developed and undeveloped gross acres.

Productive Wells

The following table sets forth our total gross and net productive wells expressed separately for natural gas and crude oil, as of December 31, 2006:

	Productive Wells (1) As of December 31, 2006			
State	Crude Oil		Natural Gas	
	Gross(2)	Net(3)	Gross(2)	Net(3)
South Texas	17.0	17.0	24.0	2
West Texas	133.0	103.4	36.0	2
Wyoming	10.0	10.0	-	
Total	160.0	130.4	60.0	4

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(1) Productive wells are producing wells and wells capable of production.
(2) A gross well is a well in which we own an interest.
(3) A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

Reserves Information

The natural gas and crude oil reserves have been estimated as of December 31, 2004, December 31, 2005, and December 31, 2006, by DeGolyer and MacNaughton, of Dallas, Texas. Natural gas and crude oil reserves, and the estimates of the present value of future net revenues there-from, were determined based on then current prices and costs. Reserve calculations involve the estimate of future net recoverable reserves of natural gas and crude oil and the timing and amount of future net revenues to be received therefrom. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain.

The following table sets forth certain information regarding estimates of our crude oil, natural gas liquids and natural gas reserves as of December 31, 2004, December 31, 2005 and December 31, 2006.

	Estimated Proved Reser	
	Proved Developed	Proved Undeveloped
As of December 31, 2004		
Crude oil (MBbls)	1,878	1,178
Natural gas (MMcf)	36,247	35,482
As of December 31, 2005		

Crude oil (MBbls)	1,942	1,093
Natural gas (MMcf)	38,797	41,474
As of December 31, 2006		
Crude oil (MBbls)	1,708	1,048
Natural gas (MMcf)	37,333	33,000

The process of estimating crude oil and natural gas reserves is complex and involves decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data. Therefore, these estimates are imprecise.

Actual future production, natural gas and crude oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil 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 annual report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and crude oil prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues referred to in this annual statement is the current market value of our estimated natural gas and crude oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the end of the year of the estimate, or alternatively, if prices subsequent to that date have increased, a price near the periodic filing date of the Company's financial statements. Because we use the full cost method to account for our natural gas and crude oil operations, we are susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. This is known as a "ceiling limitation write-down." This charge does not impact cash flow from operating activities but does reduce our stockholders' equity and reported earnings. We have experienced ceiling limitation write-downs in the past and we cannot assure you that we will not experience additional ceiling limitation write-downs in the future. For more information regarding the full cost method of accounting, you should read the information under "Management's Discussion and Analysis of Financial Condition and Results of Operation - Critical Accounting Policies."

Actual future prices and costs may be materially higher or lower than the prices and costs as of the end of the year of the estimate. Any changes in consumption by natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and crude oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and the risks associated with us or the natural gas and crude oil industry in general will affect the accuracy of the 10% discount factor.

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 natural gas and crude oil reserves, future net revenue from proved reserves and the PV-10 thereof for the natural gas and crude oil properties described in this report are based on the assumption that future natural gas and crude oil prices remain the same as natural gas and crude oil prices at December 31, 2006. The average sales prices as of such date used for purposes of such estimates were $56.42 per Bbl of crude oil and $5.83 per Mcf of natural gas. It is also assumed that we will make future capital expenditures of approximately $73.4 million in the aggregate, most of which is in the years 2007 through 2012, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

We file reports of our estimated natural gas and crude oil reserves with the Department of Energy. The reserves reported to this agency are required to be reported on a gross operated basis and therefore are not comparable to the reserve data reported herein.

Crude Oil, Natural Gas Liquids, and Natural Gas Production and Sales Prices

The following table presents our net crude oil, net natural gas liquids and net natural gas production, the average sales price per Bbl of crude oil and natural gas liquids and per Mcf of natural gas produced and the average cost of production per Mcfe of production sold, for the three years ended December 31, 2006:

	2006	2005	2004
Crude oil production (Bbls)	200,436	194,366	220
Natural gas production (Mcf)	6,515,055	4,942,355	4,403
Natural gas liquids production (Bbls)	-	-	8
Total production (Mmcfe) (2)	7,718	6,109	5
Average sales price per Bbl of crude oil	$ 62.10	$ 53.27	$ 4
Average sales price per Mcf of natural gas (1)	$ 5.78	$ 7.48	$
Average sales price per Bbl of natural gas liquids	$ -	$ -	$ 2
Average sales price per Mcfe	$ 6.49	$ 7.75	$
Average cost of production per Mcfe produced (2)	$ 1.52	$ 1.82	$

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(1) Average sales prices are net of hedging activity.
(2) Natural gas and crude oil were combined by converting crude oil and natural gas liquids to a Mcf equivalent on the basis of 1 Bbl of crude oil and natural gas liquid equals 6 Mcf of natural gas. Production costs include direct operating costs, ad valorem taxes and gross production taxes.

Drilling Activities

The following table sets forth our gross and net working interests in exploratory and development wells drilled during the three years ended December 31, 2006:

	2006		2005		2004	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Exploratory(3)						
Productive(4)						
Crude oil	-		1.0	1.0	2.0	2.0
Natural gas	1.0	1.0	1.0	1.0	-	-
Dry holes(5)	1.0	1.0	-	-	-	-
Total	2.0	2.0	2.0	2.0	2.0	2.0
Development(6)						
Productive (4)						
Crude oil	2.0	1.2	4.0	4.0	-	-
Natural gas	1.0	1.0	5.0	5.0	1.0	1.0
Dry holes (5)	-	-	1.0	1.0	1.0	1.0
Total	3.0	2.2	10.0	10.0	2.0	2.0

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(1) A gross well is a well in which we own an interest.

(2) The number of net wells represents the total percentage of working interests held in all wells (e.g., total working interest of 50% is equivalent to 0.5 net well. A total working interest of 100% is equivalent to 1.0 net well).

(3) An exploratory well is a well drilled to find and produce natural gas or crude oil in an unproved area, to find a new reservoir in a field previously found to be producing natural gas or crude oil in another reservoir, or to extend a known reservoir.

(4) A productive well is an exploratory or a development well that is not a dry hole.

(5) A dry hole is an exploratory or development well found to be incapable of producing either natural gas or crude oil in sufficient quantities to justify completion as a natural gas or crude oil well.

(6) A development well is a well drilled within the proved area of a natural gas or crude oil reservoir to the depth of stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting proved natural gas or crude oil reserves.

As of March 9, 2007, we had 3 wells in process of drilling and/or completing.

Office Facilities

Our executive and administrative offices are located at 500 North Loop 1604 East, Suite 100, San Antonio, Texas 78232, consisting of approximately 12,650 square feet leased through January 2009 at an aggregate base rate of $21,152 per month. We also have an office in Midland, Texas consisting of 570 square feet leased through February 2008 at an aggregate base rate of $439 per month.

Other Properties

We own 10 acres of land, an office building, workshop, warehouse and house in Sinton, Texas, 2.8 acres of land and an office building in Scurry County, Texas, 600 acres of land in Scurry County, Texas, 160 acres of land in Coke County, Texas and 11,537 acres of land in Pecos County, Texas. We also own 22 vehicles which are used in the field by employees. We own two workover rigs, which are used for servicing our wells.

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Item 3. Legal Proceedings

From time to time, Abraxas is involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2006, Abraxas was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on Abraxas.

Item 4. Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of our security holders during the fourth quarter of the fiscal year ended December 31, 2006.

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Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock began trading on the American Stock Exchange on August 18, 2000, under the symbol "ABP." The following table sets forth certain information as to the high and low sales price quoted for our common stock on the American Stock Exchange.

	Period	High	Low
2005			
	First Quarter	$ 2.92	$ 1.92
	Second Quarter	3.38	2.15
	Third Quarter	8.99	2.71
	Fourth Quarter	9.25	5.15
2006			
	First Quarter	$ 7.25	$ 5.24
	Second Quarter	6.50	4.00
	Third Quarter	4.86	2.90
	Fourth Quarter	4.35	2.90
2007	First Quarter (Through March 9, 2007)	$ 3.42	$ 2.81

Holders

As of March 9, 2007, we had 42,769,284 shares of common stock outstanding and had approximately 1,206 stockholders of record.

Dividends

We have not paid any cash dividends on our common stock and it is not presently determinable when, if ever, we will pay cash dividends in the future. In addition, the indenture governing our notes and our revolving credit facility prohibit the payment of cash dividends and stock dividends on our common stock. You should read the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" for more information regarding the restrictions on our ability to pay dividends.

Performance Graph

Set forth below is a performance graph comparing yearly cumulative total stockholder return on the Abraxas common stock with (a) the monthly index of stocks included in the Standard and Poor's 500 Index and (b) the Energy Capital Solutions Index (the "ECS Index") of stocks of crude oil and natural gas exploration and production companies with a market capitalization of less than $800 million (the "Comparable Companies"). The Comparable Companies are: Adams Resources & Energy Inc., Callon Petroleum Company, Carrizo Oil & Gas Inc., Clayton Williams Energy Inc., Double Eagle Petroleum Company, Edge Petroleum Corporation, Contango Oil & Gas Company, CREDO Petroleum Corporation, Markwest Hydrocarbon Inc., NGAS Resources Inc., Parallel Petroleum Corporation and Arena Resources Inc.

All of these cumulative total returns are computed assuming the value of the investment in Abraxas common stock and each index as $100.00 on December 31, 2001, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2002, 2003, 2004, 2005 and 2006.

[GRAPHIC OMITTED][GRAPHIC OMITTED]

	Dec-01	Dec-02	Dec-03	Dec-04	Dec-05	Dec-06
ECS Index	100.00	98.07	201.65	251.01	469.62	602.29
S&P 500	100.00	76.63	96.85	105.56	108.73	123.54
ABP	100.00	42.42	93.18	175.76	400.00	234.09

Item 6. Selected Financial Data

The following selected financial data as of and for the years ended is derived from our Consolidated Financial Statements. The data should be read in conjunction with our Consolidated Financial Statements and Notes thereto, and other financial information included herein. See "Financial Statements" in Item 8.

	Year Ended December 31,		
	2006	2005	2004

(Dollars in thousands except per s

Total revenue - continuing operations	$	51,723	$	48,625	$	33,854	$
Net income (loss)	$	700	$	19,117 (1)	$	12,360 (2)	$
Net income (loss) - discontinued operations	$	-	$	12,846 (1)	$	3,323	$
Net income (loss) - continuing operations	$	700	$	6,271	$	9,037	$
Net income (loss) per common share - diluted	$	0.02	$	0.46	$	0.32	$
Weighted average shares outstanding - diluted (in thousands)		43,862		41,164		38,895	
Total assets	$	116,940	$	121,866	$	152,685	$

Long-term debt, excluding current maturities	$	127,614	$	129,527	$	126,425	$
Total stockholders' equity (deficit)	$	(22,165)	$	(23,701)	$	(53,464)	$

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(1) Includes gain on the sale of foreign subsidiary of $17.3 million net of non-cash tax of $6.1 million.
(2) Includes gain on debt extinguishment of $12.6 million and a deferred tax benefit of $6.1 million. (3) Includes gain on sale of foreign subsidiaries of $ 68.9 million in 2003. (4) Includes ceiling limitation write-down of $116.0 million ($28.2 million related to continuing operations). (5) For the year ended December 31, 2003, 711,928 shares were excluded from the calculation of diluted earnings per share since their inclusion would have been antidilutive.

Item 7. Management's Discussion And Analysis Of Financial Condition And Results Of Operations

Prior to February 2005, Grey Wolf Exploration Inc. was a wholly-owned Canadian subsidiary of Abraxas. In February 2005, Grey Wolf closed on an initial public offering resulting in the substantial divestiture of our capital stock in Grey Wolf. As a result of the Grey Wolf IPO, and the significant divestiture of our interest in Grey Wolf, the results of operations of Grey Wolf are reflected in our Financial Statements and in this document as "Discontinued Operations" and our remaining operations are referred to in our Financial Statements and in this document as "Continuing Operations" or "Continued Operations." Unless otherwise noted, all disclosures are for continuing operations.

The following is a discussion of our consolidated financial condition, results of continuing operations, liquidity and capital resources. This discussion should be read in conjunction with our Consolidated Financial Statements and the Notes thereto. See "Financial Statements" in Item 8.

General

We are an independent energy company primarily engaged in the development, and production of natural gas and crude oil. 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 substantial inventory of development opportunities, which provide a basis for significant production and reserve increases. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation.

While we have attained positive net income from continuing operations in three of the last five years, there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors which significantly affect our results of operations including the following:

- the sales prices of natural gas and crude oil ;
- the level of total sales volumes of natural gas and crude oil;
- the availability of, and our ability to raise additional capital resources and provide liquidity to meet, cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Activities. The results of our operations are highly dependent upon the prices received for our natural gas and crude oil production. Substantially all of our sales of natural gas and crude oil are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our natural gas and crude oil production are dependent upon numerous factors beyond our control. Significant declines in prices for natural

gas and crude oil could have a material adverse effect on our financial condition, results of operations and quantities of reserves recoverable on an economic basis. Recently, the prices of natural gas and crude oil have been volatile. During the first half of 2006, prices for natural gas and crude oil were sustained at record or near-record levels. Supply and geopolitical uncertainties resulted in significant price volatility during the remainder of 2006 with both natural gas and crude oil prices weakening. New York Mercantile Exchange (NYMEX) futures prices for West Texas Intermediate (WTI) crude oil averaged $66.18 per barrel for the year, with a low price of about $56.27 per barrel occurring in the fourth quarter of 2006. U.S. natural gas pricing declined during 2006. NYMEX Henry Hub futures prices averaged $6.98 per million British thermal units (MMBtu) during 2006 as compared to $9.13 per MMBtu during 2005. The natural gas market continues to be driven by high natural gas storage inventories and mild early winter conditions for much of the country. NYMEX natural gas prices ended the year at about $6.30 per MMBtu. The outlook for the commodity markets in 2007 calls for continued volatility.

We seek to reduce our exposure to price volatility by hedging our production through price floors. In 2005 we incurred a hedging loss of $592,000. For the years ended December 31, 2004 and 2006 we recognized gains from hedging activities of approximately $118,000 and $646,000 respectively.

Under the terms of our revolving credit facility, we are required to maintain hedging positions with respect to not less than 25% nor more than 75% of our natural gas and crude oil production, on an equivalent basis, for a rolling six month period. We currently have the following hedges in place:

Time Period	Notional Quantities	Price
April 2007	10,000 MMbtu of production per day	Floor of $ 4.50
May 2007	10,000 MMbtu of production per day	Floor of $ 5.00
June 2007	10,000 MMbtu of production per day	Floor of $ 5.00
July 2007	10,000 MMbtu of production per day	Floor of $ 4.25
August 2007	10,000 MMbtu of production per day	Floor of $ 5.00
September 2007	10,000 MMbtu of production per day	Floor of $ 5.50

At December 31, 2006 the aggregate fair market value of our hedges was approximately $157,286.

Production Volumes. Because our proved reserves will decline as natural gas and crude oil are produced, unless we acquire additional properties containing proved reserves or conduct successful exploration and development activities, our reserves and production will decrease. Our ability to acquire or find additional reserves in the near future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures for 2006 of $26.3 million and have a capital budget for 2007 ranging from $27 to $44 million in 2007, the exact amount of which will depend on our success rate, production levels and commodity prices. During 2006, our production volumes increased by 26% over 2005.

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital going forward will primarily be cash from operating activities, funding under our revolving credit facility, cash on hand, and if an appropriate opportunity presents itself, proceeds from the sale of properties. We currently have approximately $12.7 million of availability under our revolving credit facility. We may also seek equity capital in order to fund our planned drilling expenditures.

Exploration and Development Activity. We believe that our high quality asset base, high degree of operational control and large inventory of drilling projects position us for future growth. Our properties are concentrated in locations that facilitate substantial economies of scale in drilling and production operations and more efficient reservoir management practices. We operate 94% of the properties accounting for approximately 93% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. In addition, we have 51 proved undeveloped projects and have identified over 500 drilling and recompletion opportunities on our existing acreage, the successful development of which we believe could significantly increase our daily production and proved reserves.

Our future natural gas and crude oil 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 natural gas and crude oil 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. For example, in 2006, while we have had some success in pursuing these activities, we were not able to fully replace the production volumes lost from natural field declines and property sales. If our proved reserves continue to decline in the future, our production will also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our revolving credit facility will also decline. In addition, approximately 45% of our total estimated proved reserves at December 31, 2006 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. For a more complete discussion of these risks please see "Risk Factors--We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition would be adversely affected."

Borrowings and Interest. We currently have indebtedness of approximately $127.3 million and availability of $12.7 million under the revolving credit facility. Cash interest expense was $16.6 million during 2006 and based on current interest rates and our outstanding indebtedness at March 9, 2007, would be approximately $16.3 million for 2007. This increase in cash interest expense resulted in a larger percentage of our production and cash flow from operations being used to meet our debt service requirements. As a result, we will need to increase our cash flow from operations in order to fund the development of our numerous drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

Results of Operations

Selected Operating Data. The following table sets forth certain of our operating data for the periods presented. All data has been restated to reflect continuing operations.

	Years Ended December 31 (dollars in thousands, except per unit d		
	2006	2005	
Operating revenue(1):			
Crude oil sales............................	$ 12,446	$ 10,354	$
NGLs sales	-	-	
Natural gas sales..........................	37,648	36,960	
Rig and other..............................	1,629	1,311	
Total operating revenues	$ 51,723	$ 48,625	$
Operating income	$ 19,029	$ 22,104	$
Crude oil production (MBbls)................	200.4	194.4	
NGLs production (MBbls)....................	-	-	
Natural gas production (MMcf)..............	6,515.0	4,942.4	
Average crude oil sales price (per Bbl)	$ 62.10	$ 53.27	$
Average NGLs sales price (per Bbl)	$ -	$ -	$
Average natural gas sales price (per Mcf)	$ 5.78	$ 7.48	$

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(1) Revenue and average sales prices are net of hedging activities.

Comparison of Year Ended December 31, 2006 to Year Ended December 31, 2005

Operating Revenue. During the year ended December 31, 2006, operating revenue from natural gas and crude oil sales increased by $2.8 million from

$47.3 million in 2005 to $50.1 million in 2006. The increase in revenue was primarily due to increased production volumes in 2006 as compared to 2005 offset

by lower natural gas prices realized in 2006 as compared to 2005. Higher production volumes contributed $12.1 million to natural gas and crude oil revenue, and increased crude oil realized prices contributed $1.8 million. Lower natural gas prices had a negative impact of $11.1 million on natural gas and crude oil revenue during 2006.

Crude oil sales volumes increased from 194.4 MBbls in 2005 to 200.4 MBbls during 2006. The increase in crude oil production was primarily due to production from wells in Wyoming and south Texas that were brought onto production during 2006. Natural gas sales volumes increased from 4.9 Bcf in 2005 to 6.5 Bcf in 2006. This increase was primarily due to production from a west Texas well drilled and brought onto production in August 2005. This well produced 2.2 Bcf in 2006 as compared to 0.6 Bcf in 2005. The increase in production was partially offset by natural field declines and the sale of properties in Live Oak County, Texas effective August 1, 2006. These properties produced 286.8 MMcf in 2005 compared to 182.3 MMcf in 2006 through the date of sale.

Average sales prices in 2006 net of hedging costs were:

o $62.10 per Bbl of crude oil, and
o $ 5.78 per Mcf of natural gas.

Average sales prices in 2005 net of hedging costs were:

o $53.27 per Bbl of crude oil, and
o $ 7.48 per Mcf of natural gas.

Lease Operating Expense and Production Taxes. Lease operating expense, or LOE, increased from $11.1 million in 2005 to $11.8 million in 2006. The increase in LOE was primarily due to a general increase in the cost of field services. Lower production taxes, due to the lower realized price for natural gas, were offset by increased advalorem taxes related to new wells. Our LOE on a per Mcfe basis for the year ended December 31, 2006 was $1.52 per Mcfe compared to $1.82 per Mcfe in 2005. The decrease on a per Mcfe basis was primarily due to increased production volumes in 2006 as compared to 2005.

G&A Expense. General and administrative, or G&A expense, excluding stock based compensation decreased from $5.5 million in 2005 to $4.2 million in 2006. The decrease in G&A expense in 2006 was primarily due to higher performance bonuses in 2005 as compared to 2006. Performance bonuses amounted to $162,000 in 2006, as compared to $960,000 in 2005. Our G&A expense on a per Mcfe basis decreased from $0.90 in 2005 to $0.54 in 2006. The decrease in the per Mcfe cost was due to decreased G&A expense in 2006 as compared to 2005 as well as increased production volumes in 2006 as compared to 2005.

Stock-based Compensation. In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment." SFAS No. 123R is a revision of SFAS No. 123, "Accounting for Stock Based Compensation", and supersedes APB 25. Among other items, SFAS 123R eliminates the use of APB 25 and the intrinsic value method of accounting, and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments, based on the grant date fair value of those awards, in the financial statements. Pro forma disclosure is no longer an alternative under the new standard. In December 2005, we elected early adoption of SFAS 123R .

SFAS 123R permits companies to adopt its requirements using either a "modified prospective" method or a "modified retrospective" method. We elected to use the "modified retrospective" method. Under the "modified retrospective" method, compensation cost is recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. The "modified retrospective" method, also permits entities to restate financial statements of previous periods based on proforma disclosures made in accordance with SFAS 123, accordingly we have restated prior year financial statements to reflect this method.

As a result of the retrospective adoption of SFAS 123R, the expenses previously recognized under the rules of variable accounting were reversed and a compensation expense measured according to SFAS 123R was recorded. As a result, we recognized stock-based compensation of $998,000 during 2006 as a result of the adoption of this accounting change compared to $247,000 in 2005, as restated. The increase in stock-based compensation in 2006 as compared to 2005

was due to new options granted during the latter part of 2005 and the first half of 2006 and the increase in the calculated fair value of these grants due to higher option prices as a result of the increase in the price of our Common Stock over previous option grants. Also contributing to the increase was director options grants that vest upon issuance resulting in all of the fair value of the options being recognized as stock-based compen