ABRAXAS PETROLEUM CORP
Form 10-K/A
August 11, 2008

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

**FORM 10-K/A-Number 1**

(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, 2007

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

Commission File Number 001-16071

**ABRAXAS PETROLEUM CORPORATION**

(Exact name of Registrant as specified in its charter)

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

**500 N. Loop 1604 East, Suite 100**

**San Antonio, Texas 78232**

(Address of principal executive offices)

**(210) 490-4788**

Registrant’s telephone number, including area code

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

| Title of each class: | Name of each exchange on which registered: |
| --- | --- |
| **Common Stock, par value $.01 per share** | **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 or a smaller reporting company. See definition of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer[ ] | Accelerated filer [ X ] |
| Non-accelerated filer [ ] (Do not mark if a smaller reporting company) | Smaller reporting company [ ] |

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

As of June 30, 2007, the aggregate market value of the common stock held by non-affiliates of the registrant was $200,160,952 based on the closing sale price as reported on the American Stock Exchange.

As of March 10, 2008, there were 49,038,949 shares of common stock outstanding.

Documents Incorporated by Reference:

| Document | Parts Into Which Incorporated |
|---|---|
| Portions of the registrant’s Proxy Statement relating to the 2008 Annual Meeting of Shareholders to be held on May 21, 2008. | Part III |

ABRAXAS PETROLEUM CORPORATION

FORM 10-K

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Explanatory Note: We are filing this Form 10-K/A Number 1 in response to comments we have received from the Division of Corporation Finance of the SEC. Except for Items 1, 1A, 2, 6, 7, 7A, 8 and 15, no other information included in the original report on Form 10-K filed on March 17, 2008 (the "Original Form 10-K") is amended by this Form 10-K/A Number 1. For convenience, we have repeated the Original Form 10-K in its entirety. This Form 10-K/A Number 1 amends Abraxas Petroleum Corporation's Form 10-K for the year ended December 31, 2007, originally filed with the Securities and Exchange Commission (the "SEC") on March 17, 2008.

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.

**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 expression must remember that these are forward-looking statements and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this document is generally located in the material set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management's reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- our success in development 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 consolidated 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.*

*Information contained in this report represents the operations of Abraxas Petroleum and Abraxas Energy Partners, L.P., which we refer to as the Partnership or Abraxas Energy Partners, which are consolidated for financial reporting purposes. The interest of the 52.8% owners of the Partnership are presented as minority interest. Abraxas beneficially owns the remaining 47.2% of the partnership interests. Abraxas has determined that based on its control of the general partner of the Partnership, this 47.2% owned entity should be consolidated for financial reporting purposes. The terms "Abraxas" or "Abraxas Petroleum" refer only to Abraxas Petroleum Corporation and the terms "we," "us," "our," or the "Company," refer to Abraxas Petroleum Corporation, together with its consolidated subsidiaries including Abraxas Energy Partners, L.P., unless the context otherwise requires.*

**General**

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 number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

At December 31, 2007, our core areas of operation were 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 15.8 years (7.0 years for our proved developed reserves), as of December 31, 2007. At December 31, 2007, we owned interests in 104,205 gross acres (80,281 net acres), and operated properties accounting for approximately 95% of our PV-10, affording us substantial control over the timing and incurrence of operating and capital expenditures. Approximately 91% of the Partnership's and 90% of Abraxas', or 91% of the estimated ultimate recovery of our consolidated proved developed producing reserves as of December 31, 2007 had been produced. At December 31, 2007, estimated total proved reserves were 106.8 Bcfe with an aggregate PV-10 of $216 million. During 2007, we participated in the drilling of 6 gross (5.2 net) wells with 5 gross (4.2 net) wells being successful. Total capital expenditures for 2007 were approximately $16.9 million on exploration and development projects. Overall, during 2007 our proved reserves increased by approximately 19.9 Bcfe.

**Refinancing Transaction**

On May 25, 2007, Abraxas completed a series of transactions which resulted in Abraxas' refinancing and repaying all of its outstanding indebtedness. The following is a summary of these transactions.

Abraxas formed the Partnership and contributed certain assets located in South and West Texas to a wholly-owned subsidiary of the Partnership. The assets contributed had estimated proved reserves of

approximately 65 Bcfe as of December 31, 2006 and accounted for approximately 85% of Abraxas' daily production as of such date. Abraxas, through certain wholly-owned subsidiaries, owns an approximate 47.2% interest in the Partnership, consisting of 5,131,959 common units and 227,232 general partner units. The general partner of the Partnership, Abraxas General Partner, LLC, is a wholly-owned subsidiary of Abraxas.

The Partnership sold an approximate 52.8% interest, consisting of 6,002,408 common units, at a purchase price of $16.66 per unit to various purchasers in a private placement. In connection with the private placement of the Partnership units, the Partnership entered into a registration rights agreement with regard to the limited partner units purchased by the investors. Under the registration rights agreement, as soon as practicable after May 25, 2007, the Partnership agreed (a) to prepare and file with the SEC a registration statement for (i) the initial public offering, or IPO, of the common units and (ii) a shelf registration statement for the resale of the common units by the investors and (b) to use its commercially reasonable efforts to cause the IPO registration statement and the shelf registration statement to be declared effective by February 14, 2008, which was subsequently amended to September 30, 2008. The Partnership filed the registration statement for its initial public offering in July 2007. In December 2007, the Partnership announced that it was delaying its initial public offering due to the effect that the acquisition of producing properties from St. Mary Land & Exploration Company discussed below had on the required disclosure in the registration statement.

The Partnership entered into a $150 million senior secured revolving credit facility, of which $35 million was borrowed at closing, with Société Générale, as administrative agent and issuing lender, and the other lenders signatory thereto. This facility was amended and restated in January 2008. See "-Recent Developments" and "Management's Discussion and Analysis of Financial Condition and Results of Operations–Liquidity and Capital Resources–Long-Term Indebtedness."

Abraxas sold approximately $22.5 million of its common stock in a private placement offering to several purchasers of the Partnership units. The private placement consisted of 5,874,678 shares of common stock, at a purchase price of $3.83 per share. The purchase price reflected the 10-day volume weighted average price of Abraxas' common stock prior to closing. The purchasers of the common stock were also issued five-year warrants to purchase up to an additional 1,174,939 shares of common stock, at an exercise price of $3.83 per share.

Net proceeds from these transactions of approximately $157.5 million (including $35.0 million borrowed under the Partnership's credit facility) were used to refinance and repay all of Abraxas' and its subsidiaries' outstanding indebtedness (including accrued and unpaid interest due June 1, 2007) and pay preformation and transaction expenses with the excess proceeds used to make a distribution of excess capital to Abraxas.

In addition, in June 2007, Abraxas entered into a new senior secured revolving credit facility with Société Générale, as administrative agent and issuing lender, and the lenders signatory thereto, which we refer to as the Credit Facility. The Credit Facility has a maximum commitment of $50 million. See "Management's Discussion and Analysis of Financial Condition and Results of Operations–Liquidity and Capital Resources–Long-Term Indebtedness."

As a result of these transactions and the Partnership's borrowing $35 million under its credit facility on May 25, 2007, we refinanced and terminated the loan agreement dated as of October 28, 2004 with Wells Fargo Foothill, Inc., and we refinanced and redeemed our floating rate senior secured notes due December, 2009 and terminated the Indenture dated October 28, 2004 governing the notes. The total pay-off amount under the loan agreement was $904,376 and each of the notes was redeemed at 104% of the principal amount plus accrued and unpaid interest to the date of redemption, June 24, 2007, for a total of $131.0 million or $1,048.23 per $1,000 of principal amount of the notes. As a result of the redemption of the notes, we incurred a loss on early debt extinguishment of approximately $6.5 million.

As a result of these transactions, the Company recognized a gain of $59.4 million. The gain was calculated in accordance with the requirements of Staff Accounting Bulletin 51, (Topic 5H) based on the fact that the Company elected gain treatment as a policy and the transaction met the following criteria: (1) there were no additional broad corporate reorganizations contemplated; (2) there was not a reason to believe that the gain would not be realized, since there is no additional capital raising transaction anticipated nor was

there a significant concern about the new entity’s ability to continue in existence; (3) the share price of capital raised in the private placement was objectively determined; (4) no repurchases of the new subsidiary’s units are planned; and (5) the Company acknowledges that it will consistently apply the policy, and any future transactions that might result in a loss must be recorded as a loss in the income statement.

**Recent Transactions**

On January 31, 2008, Abraxas Operating Company, a wholly-owned subsidiary of the Partnership, consummated the acquisition of certain oil and gas properties located in various states from St. Mary Land & Exploration Company, (“St. Mary”), and certain other sellers for $126.0 million. The properties are primarily located in the Rocky Mountain and Mid-Continent regions of the United States, and, at December 31, 2007, included approximately 56.7 Bcfe (9.4 MMBOE) of estimated proved reserves.

The Partnership borrowed approximately $115.6 million under its credit facility and $50 million under a new subordinated credit agreement in order to complete this acquisition and repay its previously outstanding indebtedness of $45.9 million. For a complete description of these credit facilities, please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations–Liquidity and Capital Resources–Long-Term Indebtedness”.

Simultaneously, Abraxas announced that it had completed the acquisition of certain oil and gas properties from St. Mary with estimated proved reserves of at December 31, 2007 of approximately 4.1 Bcfe (0.7 MMBOE) for a purchase price of approximately $5.6 million. Abraxas paid the purchase price from its internal funds. The right to purchase these properties had previously been assigned to Abraxas by the Partnership.

**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 fixed price swaps. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations – General – Commodity Prices and Derivative Activities” and Note 12 of the notes to our consolidated financial statements for more information regarding our derivative 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, 2007, three purchasers accounted for approximately 67% 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 10, 2008 we had 61 full-time employees. 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 iswww.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**

***Abraxas may not be able to fund the substantial capital expenditures that will be required for it to increase reserves and production.***

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

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

The borrowing bases under Abraxas' and the Partnership's credit facilities will be determined from time to time by the lenders. Reductions in estimates of natural gas and crude oil reserves could result in a reduction in the respective borrowing bases, which would reduce the amount of financial resources available under these facilities to meet our capital requirements. Such a reduction could be the result of lower commodity prices or production, inability to drill or unfavorable drilling results, changes in 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 bases decrease for any reason, both Abraxas' and the Partnership's 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 bases under Abraxas' and the Partnership's respective credit facilities are reduced, both Abraxas and the Partnership would be required to reduce their borrowings under their respective credit facilities so that such borrowings do not exceed such borrowing bases. This could further reduce the cash available to us for capital spending and, if either Abraxas or the Partnership did not have sufficient capital to reduce its respective borrowing level, Abraxas and/or the Partnership may be in default under their respective credit facilities.

Abraxas has sold producing properties to provide it with liquidity and capital resources in the past and both Abraxas and the Partnership may do so in the future. After any such sale, we would expect to utilize the proceeds to drill new wells on our remaining properties. If we cannot replace the production lost

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from properties sold with production from the remaining properties, both Abraxas' and the Partnership's cash flow from operations, including distributions of available cash from the Partnership, will likely decrease which, in turn, would decrease the amount of cash available for additional capital spending.

***We may be unable to acquire or develop additional reserves, in which case its 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. Approximately 91% of the Partnership's and 90% of Abraxas', or 91% of the estimated ultimate recovery of our consolidated proved developed producing reserves as of December 31, 2007, had been produced. Based on the reserve information set forth in our reserve report of December 31, 2007, Abraxas' average annual estimated decline rate for its net proved developed producing reserves is 9% during the first five years, 6% in the next five years, and approximately 5% thereafter. Based on the reserve information set forth in our reserve report of December 31, 2007, the Partnership's average annual estimated decline rate for its net proved developed producing reserves is 12% during the first five years, 9% in the next five years and approximately 9% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While Abraxas has had some success in finding, acquiring and developing additional reserves, Abraxas has not been able to fully replace the production volumes lost from natural field declines and prior property sales. For example, in 2006, Abraxas replaced only 7% of the reserves it produced. In 2007, however, we replaced 219% of the reserves we produced. As our proved reserves, and consequently our production, decline, our cash flow from operations, the amount of cash distributions Abraxas receives from the Partnership and the amount that we are able to borrow under our credit facilities will also decline. In addition, approximately 69% of Abraxas' and 50% of the Partnership's total estimated proved reserves at December 31, 2007 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. Even if we are successful in our development efforts, it could take several years for a significant portion of these undeveloped reserves to generate positive cash flow.

***A substantial portion of the Partnership's production is currently concentrated in one well.***

Approximately 20% of our consolidated production (22% of the Partnership's production) during 2007 was from a single well in west Texas, the La Escalera 1AH well, which is owned by the Partnership. This well represented approximately 1.0% of our proved developed reserves as of December 31, 2007 (3.75% of the Partnership's proved developed reserves) and according to our reserve report is expected to be depleted in 2011. 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 and on the distributions of available cash Abraxas receives from the Partnership.

***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 69% of Abraxas and 50% of the Partnership's, or 56% of our consolidated total estimated proved reserves at December 31, 2007, 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 and the amount of any distributions that Abraxas may receive from the Partnership will decrease.

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

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

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

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

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

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

A breach of any of these covenants or either Abraxas' or the Partnership's inability to comply with the required financial ratios or financial condition tests could result in a default under Abraxas' new credit facility and/or the Partnership's credit facility. A default, if not cured or waived, could result in all of our

indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable or favorable to us.

***The marketability of our production depends largely upon the availability, proximity and capacity of 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.***

Both Abraxas and the Partnership enter into derivative contracts, which we sometimes refer to as hedge 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 realized and unrealized derivative losses of $139,000 and $452,000, respectively, resulting from the price floors we established. For the year ended December 31, 2006, we had realized and unrealized derivative gains of $565,000 and $81,000 respectively, and in 2007, we realized a gain of $1.9 million and incurred an unrealized loss of $6.3 million on derivative contracts in place at December 31, 2007. Under the terms of the Partnership Credit Facility, Abraxas Energy Partners was required to enter into derivative contracts for specified volumes, which equated to approximately 85% of the estimated oil and gas production through December 31, 2011 from its net proved developed producing reserves. Abraxas Energy Partners has entered into NYMEX–based fixed price commodity swaps at then current market prices.

The following table sets forth our derivative contract position at March 10, 2008:

| **Period Covered** | **Product** | **Volume (Production per day)** | **Weighted Average Fixed Price** |
|---|---|---|---|
| Year 2008 | Natural Gas | 11,840 Mmbtu | $8.44 |
| Year 2008 | Crude Oil | 1,105 Bbl | $84.84 |
| Year 2009 | Natural Gas | 10,595 Mmbtu | $8.45 |
| Year 2009 | Crude Oil | 1,000 Bbl | $83.80 |
| Year 2010 | Natural Gas | 9,130 Mmbtu | $8.22 |
| Year 2010 | Crude Oil | 895 Bbl | $83.26 |
| Year 2011 | Natural Gas | 8,010 Mmbtu | $8.10 |
| Year 2011 | Crude Oil | 810 Bbl | $86.45 |

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

- highly volatile 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

***Use of our net operating loss carryforwards may be limited.***

At December 31, 2007, we had, subject to the limitation discussed below, $178.1 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2027 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 and $47.2 million at December 31, 2007.

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

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

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

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

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

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

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

- government regulation and taxation. In addition, the actual amount of cash that the Partnership will have available for distribution will depend on other factors, including:

- the level of its capital expenditures;
- its ability to make borrowings under its credit facility to pay distributions;
- sources of cash used to fund acquisitions;
- debt service requirements and restrictions on distributions contained in its credit facility or future debt agreements;
- fluctuations in its working capital needs;
- general and administrative expenses;
- cash settlement of hedging positions;
- timing and collectibility of receivables; and
- the amount of cash reserves, which the Partnership expects to be substantial, established by its general partner for the proper conduct of its business.

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

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

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

Use of cash generated from operations by the Partnership will reduce cash available for distribution to Abraxas as a unitholder. The Partnership's ability to borrow from its credit facility or to obtain additional bank financing or to access the capital markets for future equity or debt offerings may be limited by its

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

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

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

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

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

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

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

***The general partner of the Partnership, which is wholly- owned by Abraxas, may be removed as general partner with the consent of unitholders owning at least $66^2/3\%$ of the common units, including units beneficially owned by Abraxas.***

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

**Risks Related to Our Industry**

***Market conditions for 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 82% of our production and reserves were natural gas at December 31, 2007 (68% following the acquisitions completed in January 2008). 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 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, 2007. The sales prices as of such date used for purposes of such estimates were $6.33 per Mcf of natural gas and $87.30 per Bbl of crude oil. This compares with $5.83 per Mcf of natural gas and $56.42 per Bbl of crude oil as of December 31, 2006. These estimates also assume that Abraxas and the Partnership will make future capital expenditures of approximately $111.3 million in the aggregate through 2012, which are necessary to develop and realize the value of proved undeveloped reserves on our properties. In addition, approximately 56% of our total estimated proved reserves as of December 31, 2007 were undeveloped. By their nature, estimates of undeveloped reserves are less certain than proved developed reserves. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth in this report.

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

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

- supply of and demand for oil and gas;
- actual prices we receive for oil and gas;
- our actual operating costs;
- the amount and timing of our capital expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flow, which is required by the SEC, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

***Our operations are subject to the numerous risks of 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

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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**

***Abraxas does not pay dividends on common stock.***

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

***Shares eligible for future sale may depress our stock price.***

At March 10, 2008, Abraxas had 49,038,949 shares of common stock outstanding of which 4,080,727 shares were held by affiliates and, in addition, 2,527,699 shares of common stock were subject to outstanding options granted under certain stock option plans (of which 1,872,866 shares were vested at March 10, 2008).

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

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

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

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

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

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

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

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

***An active market may not develop for the common stock.***

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

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

Abraxas is currently authorized to issue 200,000,000 shares of common stock with such rights as determined by our board of directors. Abraxas may in the future issue its previously authorized and unissued securities, resulting in the dilution of the ownership interests of current stockholders. In addition, under the terms of the Exchange and Registration Rights Agreement entered into in connection with the transactions completed in May 2007, Abraxas may be required to issue additional shares of common stock. Under the terms of this agreement, in the event that the Partnership has not consummated its initial public offering by November 15, 2008, which we refer to as the Trigger Date, the investors will have the right to convert their common units obtained in the private placement offering into shares of common stock. Each common unit will be convertible into a number of shares of common stock equal to $16.66 divided by the volume weighted average price of the common stock for the ten (10) business day period immediately prior to the first business day following the Trigger Date times 0.9. If stockholder approval is required for such issuance, Abraxas has agreed to call a special meeting of the stockholders within 60 days of November 15, 2008, which we refer to as the Exchange Filing Date, and the executive officers and directors of Abraxas have agreed to vote the shares of common stock then held by them in favor of such issuance. Under this agreement, Abraxas also agreed within 30 days of the Trigger Date, to prepare and file with the Securities and Exchange Commission a registration statement, which we refer to as the Exchange Registration Statement, to enable the resale of the common stock, which we refer to as the Exchange Shares, by the investors or their transferees from time to time over any national stock exchange on which the common

stock is then traded, or in privately-negotiated transactions. If the Exchange Registration Statement is not declared effective by the 120th day following the Trigger Date (which period would be extended to the 180th day following the Trigger Date under certain circumstances), then in addition to any other rights the investors may have under the Exchange and Registration Rights Agreement or under applicable law, Abraxas is required to pay an amount in cash as liquidated damages and not as a penalty, equal to 1.0% of the product of $3.83 times the number of Exchange Shares then held by such investor for each 30-day period until the Exchange Registration Statement is declared effective. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of the common stock. Abraxas may also issue additional shares of common stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of the common stock.

## Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

### Primary Operating Areas

At December 31, 2007, our properties were located in south and west Texas and east central Wyoming. The following table sets forth certain information about our properties as of December 31, 2007:

| Area | Producing Wells (Gross) | Producing Wells (Net) | Average Working Interest | Estimated Net Proved Reserves (Bcfe) | Net Production (Mmcfe) | Net Daily Production (MMcfepd) |
|---|---|---|---|---|---|---|
| **Wyoming** | | | | | | |
| Brooks Draw | 10.0 | 10.0 | 100% | 1.4 | 86 | 0.2 |
| **West Texas** | | | | | | |
| ROC Complex | 72.0 | 48.9 | 68% | 39.2 | 2,141 | 5.9 |
| Oates SW | 6.0 | 6.0 | 100% | 17.7 | 2,043 | 5.6 |
| IRA | 95.0 | 74.7 | 79% | 11.6 | 341 | 0.9 |
| **South Texas** | | | | | | |
| Edwards | 8.0 | 7.5 | 94% | 29.3 | 1,149 | 3.1 |
| Portilla | 32.0 | 32.0 | 100% | 5.9 | 766 | 2.1 |
| Wilcox | 8.0 | 5.0 | 62% | 1.7 | 224 | 0.6 |
| Total | 231.0 | 184.1 | 80% | 106.8 | 6,749 | 18.5 |

*Texas*

At December 31, 2007, our operations were concentrated in south and west Texas with over 98% of the PV-10 of our natural gas and crude oil properties at December 31, 2007 located in those two regions. We operate 93% of our wells in Texas. During 2007, we drilled a total of 6 new wells (5.2 net) in Texas with an 83% success rate.

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 93% working interest in 48 wells with average production of 214 net Bbls of crude oil and 4,577 net Mcf of natural gas per day for the year ended December 31, 2007. As of December 31, 2007, we had estimated net proved reserves in south Texas of 36.8 Bcfe (89% natural gas) with a PV-10 of $64.3 million, 47% of which was attributable to proved developed reserves.

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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 20% of our production in 2007.

In west Texas, we own an average 69% working interest in 173 wells with average daily production of 287 net Bbls of crude oil and 9,841 net Mcf of natural gas per day for the year ended December 31, 2007. As of December 31, 2007, we had estimated net proved reserves in west Texas of 68.6 Bcfe (80% natural gas) with a PV-10 of $147.6 million, 55% of which was attributable to proved developed reserves.

*Wyoming*

At December 31, 2007, Abraxas held 41,079 net acres in the Powder River Basin in east central Wyoming and had drilled and operates ten wells in Converse and Niobrara counties that were completed in the Muddy, Mowry, Turner, and Niobrara formations. Abraxas owns a 100% working interest in these wells that produced a combined average of 39 net barrels of crude oil per day in 2007. As of December 31, 2007, Abraxas had estimated net proved producing reserves in Wyoming of 226,892 barrels of crude oil with a PV-10 of $3.8 million.

Abraxas is currently in the process of permitting new horizontal Mowry Shale wells while monitoring industry activity in this new area. Abraxas plans to drill several more wells in Wyoming during 2008.

**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 December 31, 2007:

| | Developed Acreage (1) | | Undeveloped Acreage (2) | | Fee Mineral Acreage(3) | | |
|---|---|---|---|---|---|---|---|
| | Gross Acres (4) | Net Acres (5) | Gross Acres (6) | Net Acres (5) | Gross Acres (6) | Net Acres | Total Net Acres |
| South Texas (7) | 4,727 | 4,280 | 3,286 | 2,456 | — | — | 6,736 |
| West Texas(8) | 21,687 | 16,283 | 15,892 | 10,887 | 12,007 | 5,272 | 32,442 |
| Wyoming-Abraxas | 3,400 | 3,400 | 43,126 | 37,679 | — | — | 41,079 |
| N. Dakota-Abraxas | — | — | 80 | 24 | — | — | 24 |
| Total | 29,814 | 23,963 | 62,384 | 51,046 | 12,007 | 5,272 | 80,281 |

(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.
(7) The following shows the amount of acreage owned by each of Abraxas and the Partnership in South Texas as of December 31, 2007:

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| | Developed Acreage | | Undeveloped Acreage | | |
|---|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres | Total Net Acres |
| Abraxas | 908 | 636 | 3,231 | 2,415 | 3,051 |
| Partnership | 3,819 | 3,644 | 55 | 41 | 3,685 |
| Total | 4,727 | 4,280 | 3,286 | 2,456 | 6,736 |

(8) The following shows the amount of acreage owned by each of Abraxas and the Partnership in West Texas as of December 31, 2007:

| | Developed Acreage | | Undeveloped Acreage | | Fee Mineral Acreage | | |
|---|---|---|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres | Gross Acres(6) | Net Acres | Total Net Acres |
| Abraxas | 14,996 | 10,571 | 14,465 | 10,100 | 12,007 | 5,272 | 25,943 |
| Partnership | 10,335 | 8,225 | 1,766 | 1,127 | - | - | 9,352 |
| Total (1) | 25,331 | 18,796 | 16,231 | 11,227 | 12,007 | 5,272 | 35,295 |

(1) Abraxas and the Partnership have common ownership in certain developed and undeveloped acreage with each having rights at varying depths.

**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, 2007:

| | Productive Wells (1) As of December 31, 2007 | | | |
|---|---|---|---|---|
| State | Crude Oil | | Natural Gas | |
| | Gross(2) | Net(3) | Gross(2) | Net(3) |
| South Texas (4) | 21.5 | 21.5 | 26.5 | 23.0 |
| West Texas (5) | 132.0 | 103.5 | 41.0 | 26.1 |
| Wyoming-Abraxas | 10.0 | 10.0 | — | — |
| Total | 163.5 | 135.0 | 67.5 | 49.1 |

(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.
(4) The following table sets forth the productive wells owned by Abraxas and the Partnership in South Texas as of December 31, 2007:

| | Productive Wells (1) As of December 31, 2007 | | | |
|---|---|---|---|---|
| | Crude Oil | | Natural Gas | |

| | Gross | Net | Gross | Net |
|---|---|---|---|---|
| Abraxas | - | - | 7.0 | 5.0 |
| Partnership | 21.5 | 21.5 | 19.5 | 18.0 |
| Total | 21.5 | 21.5 | 26.5 | 23.0 |

(5) The following table sets forth the productive wells owned by Abraxas and the Partnership in West Texas as of December 31, 2007:

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| | Productive Wells (1) | | | |
|---|---|---|---|---|
| | As of December 31, 2007 | | | |
| | Crude Oil | | Natural Gas | |
| | Gross | Net | Gross | Net |
| Abraxas | 93.0 | 73.5 | 13.0 | 7.6 |
| Partnership | 39.0 | 30.0 | 28.0 | 18.5 |
| Total | 132.0 | 103.5 | 41.0 | 26.1 |

**Reserves Information**

The natural gas and crude oil reserves have been estimated as of December 31, 2005, December 31, 2006, and December 31, 2007, 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. Proved oil and gas reserves are the estimated quantities of crude oil and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company’s proved reserves are located in the continental United States. Proved reserves were estimated in accordance with guidelines established by the United States Securities and Exchange Commission and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements; therefore, year-end prices and costs were used in estimating net cash flows.

The following table sets forth certain information regarding estimates of our crude oil, natural gas liquids and natural gas reserves as of December 31, 2005, December 31, 2006 and December 31, 2007.

| | **Estimated Proved Reserves** | | |
|---|---|---|---|
| | Proved Developed | Proved Undeveloped | Total Proved |
| As of December 31, 2005 | | | |
| Crude oil (MBbls) | 1,942 | 1,093 | 3,035 |
| Natural gas (MMcf) | 38,797 | 41,474 | 80,271 |
| As of December 31, 2006 | | | |
| Crude oil (MBbls) | 1,708 | 1,048 | 2,756 |
| Natural gas (MMcf) | 37,333 | 33,000 | 70,333 |
| As of December 31, 2007 | | | |
| Abraxas | | | |
| Crude oil (MBbls) | 1,017 | 908 | 1,925 |
| Natural gas (MMcf) | 4,574 | 17,969 | 22,543 |
| Partnership | | | |

| | | | |
|---|---|---|---|
| Crude oil (MBbls) | 1,167 | 39 | 1,206 |
| Natural gas(Mmcf) | 29,334 | 36,126 | 65,460 |
| Total | | | |
| Crude oil (MBbls) | 2,184 | 947 | 3,131 |
| Natural gas (MMcf) | 33,908 | 54,095 | 88,003 |

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 Report on Form 10-K 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 consolidated 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 Operations – 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, 2007. The average sales prices as of such date used for purposes of such estimates were $87.30 per Bbl of crude oil and $6.33 per Mcf of natural gas. It is also assumed that we will make future capital expenditures of approximately $111.3 million in the aggregate in the years 2008 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, 2007:

| | 2005 | 2006 | 2007 | |
|---|---|---|---|---|
| Crude oil production (Bbls) | 194,366 | 200,436 | 196,944 | (3) |
| Natural gas production (Mcf) | 4,942,355 | 6,515,055 | 5,567,668 | (3) |
| Total production (Mmcfe) (1) | 6,109 | 7,718 | 6,749 | (3) |
| Average sales price per Bbl of crude oil | $ 53.27 | $ 62.10 | $ 65.30 | |

| | | | |
|---|---|---|---|
| Average sales price per Mcf of natural gas (2) | $ 7.57 | $ 5.77 | $ 6.46 |
| Average sales price per Mcfe (2) | $ 7.82 | $ 6.48 | $ 7.23 |
| Average cost of production per Mcfe produced (1) | $ 1.82 | $ 1.52 | $ 1.67 |

(1) 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.
(2) Average sales prices are net of realized hedging activity.
(3) The following sets forth the production for Abraxas and the Partnership in 2007:

| | |
|---|---|
| **Abraxas :** | |
| Crude oil production (Bbls) | 119,188 |
| Natural gas production (Mcf) | 2,815,045 |
| Total production (Mmcfe) | 3,530,173 |
| **Partnership :** | |
| Crude oil production (Bbls) | 77,756 |
| Natural gas production (Mcf) | 2,752,623 |
| Total production (Mmcfe) | 3,219,159 |

**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, 2007:

| | 2005 | | 2006 | | 2007 | |
|---|---|---|---|---|---|---|
| | Gross(1) | Net(2) | Gross(1) | Net(2) | Gross(1) | Net(2) |
| Exploratory(3) | | | | | | |
| Productive(4) | | | | | | |
| Crude oil | 1.0 | 1.0 | - | | - | - |
| Natural gas | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 0.6 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Dry holes(5) | | | 1.0 | | 1.0 | |
| | - | - | | 1.0 | | 1.0 |
| | | | 2.0 | 2.0 | 2.0 | 1.6 |
| Total | 2.0 | 2.0 | | | | |
| Development(6) | | | | | | |
| Productive (4) | | | | | | |
| | | | 2.0 | 1.2 | 3.0 | 2.6 |
| Crude oil | 4.0 | 4.0 | | | | |
| | | | 1.0 | 1.0 | 1.0 | 1.0 |
| Natural gas | 5.0 | 5.0 | | | | |
| Dry holes (5) | | | - | - | - | - |
| | 1.0 | 1.0 | | | | |
| | | | 3.0 | 2.2 | 4.0 | 3.6 |
| Total | 10.0 | 10.0 | | | | |

___________________

(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 10, 2008, we had two operated wells and numerous non-operated 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 15,500 square feet leased through January 2009 at an aggregate base rate of $26,400 per month. We also have an office in Midland, Texas consisting of 570 square feet leased through February 2009 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, 50 acres of land in La Vaca County, Texas, 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.

**Item 3. Legal Proceedings**

From time to time, we are involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2007, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial condition.

**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, 2007.

**Part II**

**?tem 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities**

**Market Information**

Abraxas 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 Abraxas’ common stock on the American Stock Exchange.

| | Period | High | Low |
|---|---|---|---|
| 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 | $ 3.47 | $ 2.72 |
| | Second Quarter | 4.68 | 2.95 |
| | Third Quarter | 4.73 | 3.25 |
| | Fourth Quarter | 4.85 | 3.19 |
| 2008 | First Quarter (Through March 10, 2008) | $ 4.49 | $ 3.15 |

**Holders**

As of March 10, 2008, Abraxas had 49,038,949 shares of common stock outstanding and had approximately 1,240 stockholders of record.

**Dividends**

Abraxas has not paid any cash dividends on its common stock and it is not presently determinable when, if ever, Abraxas will pay cash dividends in the future. In addition, our credit facility prohibits the payment of cash dividends on the 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 Abraxas’ 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, 2002, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2003, 2004, 2005, 2006 and 2007.

| | Dec. 31, 2002 | Dec. 31, 2003 | Dec. 31, 2004 | Dec. 31, 2005 | Dec. 31, 2006 | Dec. 31, 2007 |
|---|---|---|---|---|---|---|
| ECS Index | 100.00 | 194.68 | 245.17 | 464.12 | 627.49 | 981.33 |
| S&P 500 | 100.00 | 96.40 | 137.75 | 141.88 | 161.20 | 166.89 |
| ABP | 100.00 | 219.64 | 414.29 | 942.86 | 551.79 | 689.29 |

The information contained above under the caption "Stock Performance Graph" is being "furnished" to the Securities and Exchange Commission and shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission , nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate it by reference into such filing.

**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, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2003 | | 2004 | | 2005 | | 2006 | 2007 | |
| | (Dollars in thousands except per share data) | | | | | | | | |
| Total revenue - continuing operations | $30,380 | | $33,854 | | $49,216 | | $51,077 | $48,309 | |
| Net income | $56,798 | (3) | $12,360 | (2) | $19,117 | (1) | $700 | $56,702 | (5) |
| Net income - discontinued operations | $70,024 | (3) | $3,323 | | $12,846 | (1) | $— | $— | |

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| | | | | | |
|---|---|---|---|---|---|
| Net income (loss) - continuing operations | $(13,226) | $9,037 | $6,271 | $700 | $56,702 |
| Net income per common share – diluted | $1.61 | $0.32 | $0.46 | $0.02 | $1.19 |
| Weighted average shares outstanding – diluted (in thousands) | 35,364 (4) | 38,895 | 41,164 | 43,862 | 47,593 |
| Total assets | $126,437 | $152,685 | $121,866 | $116,940 | $147,119 |
| Long-term debt, excluding current maturities | $184,649 | $126,425 | $129,527 | $127,614 | $45,900 |
| Total stockholders' equity (deficit) | $(72,203) | $(53,464) | $(23,701) | $(22,165) | $55,847 |

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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) 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.
(5) Includes a gain on sale of assets of $59.4 million.

**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 number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary exploration projects in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth on our current production levels and associated reserves.

While we have attained positive net income from continuing operations in four 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;

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- 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. The prices we receive for our production are dependent upon spot market prices, price differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. 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, cash flows 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. During 2007, crude oil prices remained strong while natural gas prices remained strong but weakened during the course of the year. New York Mercantile Exchange (NYMEX) spot prices for West Texas Intermediate (WTI) crude oil averaged $72.32 per barrel during 2007. WTI crude oil ended the year at $96.01 per barrel. NYMEX Henry Hub spot prices for natural gas averaged $6.98 per million British thermal units (MMBtu) during 2007 and ended the year at $7.47.

The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location,
- adjustments for BTU content; and
- gathering, processing and transportation costs.

During 2007, differentials averaged $3.10 per Boe of crude oil and $1.00 per Mcf of natural gas. We expect to realize greater differentials during 2008 because of the increased percentage of our production from the Rocky Mountain region which experience higher differentials than our Texas properties. Under the terms of the Partnership Credit Facility, Abraxas Energy Partners was required to enter into derivative contracts for specified volumes, which equated to approximately 85% of the estimated oil and gas production through December 31, 2011 from its net proved developed producing reserves. The Partnership intends to enter into derivative contracts in the future to reduce the impact of price volatility on its cash flow. By removing a significant portion of price volatility on its future oil and gas production, the Partnership believes it will mitigate, but not eliminate, the potential effects of changing commodity gas prices on its cash flow from operations for those periods. However, because the prices at which we have hedged our oil and gas production are significantly less than current, historically high commodity prices, we will not realize increased cash flow on the portion of our production that we have hedged as a result of these high prices and we will sustain realized and unrealized losses on our derivative contracts. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative position at March 10, 2008:

| **Period Covered** | **Product** | **Volume (Production per day)** | **Fixed Price** |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Year 2008 | Natural Gas | 11,840 Mmbtu | $8.44 |
| Year 2008 | Crude Oil | 1,105 Bbl | $84.84 |
| Year 2009 | Natural Gas | 10,595 Mmbtu | $8.45 |
| Year 2009 | Crude Oil | 1,000 Bbl | $83.80 |
| Year 2010 | Natural Gas | 9,130 Mmbtu | $8.22 |
| Year 2010 | Crude Oil | 895 Bbl | $83.26 |
| Year 2011 | Natural Gas | 8,010 Mmbtu | $8.10 |
| Year 2011 | Crude Oil | 810 Bbl | $86.45 |

At December 31, 2007, the aggregate fair market value of our derivative contracts was approximately $(9.1) million.

***Production Volumes.*** Because our proved reserves will decline as natural gas and crude oil are produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities, our reserves and production will decrease. Approximately 90% of the estimated ultimate recovery of Abraxas' and 91% of the Partnership's, or 91% of our consolidated proved developed producing reserves as of December 31, 2007 had been produced. Based on the reserve information set forth in our reserve report of December 31, 2007, Abraxas' average annual estimated decline rate for its net proved developed producing reserves is 9% during the first five years, 6% in the next five years, and approximately 5% thereafter. Based on the reserve information set forth in our reserve report of December 31, 2007, the Partnership's average annual estimated decline rate for its net proved developed producing reserves is 12% during the first five years, 9% in the next five years and approximately 9% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While Abraxas has had some success in finding, acquiring and developing additional revenues, Abraxas has not been able to fully replace the production volumes lost from natural field declines and prior property sales. For example, in 2006, Abraxas replaced only 7% of the reserves it produced. In 2007, however, we replaced 219% of the reserves we produced. 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. Please see "–Results of Operations–Selected Operation Data" for a presentation of our production levels for the three years.

We had capital expenditures during 2007 of $26.9 million including a $10.0 million deposit on the St. Mary property acquisition that closed in January, 2008, and have a capital budget for 2008 of approximately $55 million, of which $35 million is applicable to Abraxas and $20 million applicable to the Partnership. The final amount of our capital expenditures for 2008 will depend on our success rate, production levels, the availability of capital and commodity prices.

***Availability of Capital.*** As described more fully under "Liquidity and Capital Resources" below, Abraxas' sources of capital going forward will primarily be cash from operating activities, funding under the Credit Facility, cash on hand, distributions from the Partnership and if an appropriate opportunity presents itself, proceeds from the sale of properties. Abraxas Energy Partners' principal sources of capital will be cash from operating activities, borrowings under the Partnership Credit Facility, and sales of debt or equity securities if available to it. At December 31, 2007, Abraxas had approximately $6.5 million of availability under the Credit Facility and the Partnership had approximately $19.1 million of availability under the Partnership Credit Facility. Upon the closing of the acquisition of properties described in "General – Business – Recent Events," the Partnership borrowed $115.6 million under its Amended Partnership Credit Facility and $50 million under its subordinate credit agreement. Upon the completion of this transaction, the Partnership had $24.4 million available under its Amended Credit Facility.

***Exploration and Development Activity.*** We believe that our high quality asset base, high degree of operational control and 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. At December 31, 2007, we operated 95% of the properties accounting for approximately 95% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. Over the five years ended December 31, 2007, we drilled 33 gross (31.4 net) wells of which 88% resulted in commercially productive wells.

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. In 2006, for example, Abraxas replaced only 7% of the reserves it produced. In 2007, however, we replaced 219% of our reserves. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flow from operations, distributions of available cash from the Partnership to Abraxas and the amount that Abraxas is able to borrow under its credit facility

and that the Partnership will be able to borrow under its credit facility will also decline. In addition, approximately 69% of Abraxas' and 56% of the Partnership's estimated proved reserves at December 31, 2007 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. We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

***Borrowings and Interest.*** Abraxas Energy Partners currently has indebtedness of approximately $115.6 under the Partnership Credit Facility and $50 million under its Subordinated Credit Agreement. The Partnership has $24.4 million available under its Partnership Credit Facility. Abraxas has availability of $6.5 million under its $50 million Credit Facility. There is currently no outstanding balance under this facility. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would 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. Average prices reflect realized prices including the impact of hedging activities.

| | **Years Ended December 31,** *(dollars in thousands, except per unit data.)* | | |
|---|---|---|---|
| | **2005** | **2006** | **2007** |
| Operating revenue(1): | | | |
| Crude oil sales | $10,354 | $12,446 | $13,633 |
| Natural gas sales | 37,551 | 37,002 | 33,273 |
| Rig and other | 1,311 | 1,629 | 1,403 |
| Total operating revenues | $49,216 | $51,077 | $48,309 |
| | | | |
| Operating income | $22,695 | $18,383 | $15,524 |
| | | | |
| Crude oil production (MBbls) | 194.4 | 200.4 | 196.9 |
| Natural gas production (MMcf) | 4,942.4 | 6,515.0 | 5,567.7 |
| | | | |
| Average crude oil sales price (per Bbl) | $53.27 | $62.10 | $65.30 |
| Average natural gas sales price (per Mcf) | $7.60 | $5.77 | $6.46 |

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(1) Revenue is before the impact of hedging activities.

**Comparison of Year Ended December 31, 2007 to Year Ended December 31, 2006**

*Operating Revenue*. During the year ended December 31, 2007, operating revenue from natural gas and crude oil sales decreased by $2.5 million from $49.4 million in 2006 to $46.9 million in 2007. The decrease in revenue was primarily due to decreased production volumes in 2007 as compared to 2006 offset by higher natural gas and crude oil prices realized in 2007 as compared to 2006. Lower production volumes had a negative impact of $5.6 million which was partially offset by higher realized prices, excluding derivative activities, which contributed $3.1 million to natural gas and crude oil revenue for the year ended December 31, 2007.

Crude oil sales volumes decreased from 200.4 MBbls in 2006 to 196.9 MBbls during 2007. The decrease in crude oil production was primarily due to natural field declines. Natural gas sales volumes decreased from 6.5 Bcf in 2006 to 5.6 Bcf in 2007. This decrease was primarily due to the sale of properties in Live Oak County, Texas effective August 1, 2006, as well as natural field declines. Properties sold in

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2006 contributed 182.3 MMcfe during 2006 prior to their sale. Production from a west Texas well drilled and brought onto production in August 2005 produced 2.2 Bcf in 2006 as compared to 1.4 Bcf in 2007. The west Texas well, the La Escalera 1AH well, provided approximately 20% of our Mcfe production for the year ended December 31, 2007.

Average sales prices in 2007, before realized loss on derivative contracts were:

- $65.30 per Bbl of crude oil, and
- $ 5.77 per Mcf of natural gas.

Average sales prices in 2006, before realized loss on derivative contracts were:

- $62.10 per Bbl of crude oil, and
- $ 7.57 per Mcf of natural gas.

*Lease Operating Expense and Production Taxes*. Lease operating expense, or LOE, decreased from $11.8 million in 2006 to $11.3 million in 2007. The decrease in LOE was primarily due to a decrease in ad valorem and severance taxes. Severance and ad valorem taxes decreased from $4.5 million in 2006 to $3.8 million in 2007. The decrease was due to revisions of values of some properties resulting in a lower ad valorem tax assessment. Excluding taxes, LOE increased from $7.3 million in 2006 to $7.4 million in 2007. This increase was due to a general increase in the cost of field services. Our LOE on a per Mcfe basis for the year ended December 31, 2007 was $1.67 per Mcfe compared to $1.52 per Mcfe in 2006. The increase on a per Mcfe basis was primarily due to a decrease in production volumes in 2007 as compared to 2006.

*G&A Expense.* General and administrative, or G&A expense, excluding stock based compensation increased from $4.2 million in 2006 to $5.4 million in 2007. The increase in G&A expense in 2007 was primarily due to new, incremental G&A costs incurred by Abraxas Energy Partners and to higher performance bonuses in 2007 as compared to 2006. Performance bonuses amounted to $162,000 in 2006, as compared to $1.1 million in 2007. Our G&A expense on a per Mcfe basis increased from $0.54 in 2006 to $0.81 in 2007. The increase in the per Mcfe cost was due to increased G&A expense in 2007 as compared to 2006 as well as decreased production volumes in 2007 as compared to 2006.

*Stock-based Compensation.*We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. For the year ended December 31, 2006 and 2007, stock based compensation was approximately $998,000 and $996,000 respectively.

*DD&A Expense.* Depreciation, depletion and amortization, or DD&A, expense decreased from $14.9 million in 2006 to $14.3 million in 2007. The decrease in DD&A was primarily due to increased reserves as of December 31, 2007 as compared to December 31, 2006, as well as a decrease in production volumes in 2007 as compared to 2006. Our DD&A expense on a per Mcfe basis for 2007 was $2.12 per Mcfe as compared to $1.94 per Mcfe in 2006. The increase in the per Mcfe basis was due to the decreased production volumes in 2007 as compared to 2006.

*Interest Expense.* Interest expense decreased to $8.4 million in 2007 compared to $16.8 million for in 2006. The decrease in interest expense was due to the redemption of our outstanding senior secured notes and refinancing and repayment of our credit facility with Wells Fargo Foothill in May 2007.

***Loss on debt extinguishments.*** The loss on debt extinguishment consists primarily of the call premium and interest that was paid in connection with the refinancing and redemption of our senior secured notes in May 2007. *Income taxes.* Federal income tax and state of Texas margin tax have been recognized for the year ended December 31, 2007 as a result of the gain on the sale of assets during the period. No deferred income

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tax expense or benefit has been recognized due to losses or loss carryforwards and valuation allowance, which has been recorded against such benefits.

*Gain on sale of assets.* As a result of the transactions related to the formation of Abraxas Energy Partners, Abraxas Petroleum recognized a gain of $59.4 million. This gain was calculated based on the requirements of Staff Accounting Bulletin 51, (Topic 5H) based on the fact that the Company elected gain treatment as a policy and the transaction met the following criteria: (1) there were no additional broad corporate reorganizations contemplated; (2) there was not a reason to believe that the gain would not be realized, since there is no additional capital raising transaction anticipated nor was there a significant concern about the new entity’s ability to continue in existence; (3) the share price of capital raised in the private placement was objectively determined; (4) no repurchases of the new subsidiary’s units are planned; and (5) the Company acknowledges that it will consistently apply the policy, and any future transactions that might result in a loss must be recorded as a loss in the income statement.

*Income (loss) from derivative contracts.* We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by SFAS 133; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Abraxas Energy Partners has entered into a series of NYMEX–based fixed price commodity swaps, the estimated unearned value of which was approximately $(9.1) million as of December 31, 2007. For the year ended December 31, 2007, we realized a gain on these derivative contracts of $1.9 million. As of December 31, 2007 we incurred unrealized losses on derivative contracts in place of $(6.3) million.

*Minority interest.* Minority interest represents the share of the net income (loss) of Abraxas Energy Partners for the period owned by the partners other than Abraxas Petroleum. For the year ended December 31, 2007, the minority interest in the net loss of the Partnership was approximately $1.8 million.

**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 $1.5 million from $47.9 million in 2005 to $49.4 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 $10.9 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, the La Escalera IAH 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 before the impact of derivative activities were:

- $62.10 per Bbl of crude oil, and
- $ 5.77 per Mcf of natural gas.

Average sales prices in before the impact of derivative activities were:

- $53.27 per Bbl of crude oil, and

- $ 7.57 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.* We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. For the year ended December 31, 2005 and 2006, stock based compensation was approximately $247,000 and $998,000 respectively.

*DD&A Expense.* Depreciation, depletion and amortization, or DD&A, expense increased from $8.9 million in 2005 to $14.9 million in 2006. The increase in DD&A was primarily due to increased production volumes in 2006 as well as a general increase in drilling and development cost in 2006 as compared to 2005. The increase in development cost was a result of an increase in estimated future development cost which causes an increase in the depletion base on which depletion is calculated. Our DD&A expense on a per Mcfe basis for 2006 was $1.94 per Mcfe as compared to $1.46 per Mcfe in 2005. The increase in the per Mcfe basis was due to the increased depletion base as a result of higher estimated future development cost in 2006 as compared to 2005, which was partially offset by higher production volumes in 2006.

*Interest Expense.* Interest expense increased from $14.0 million to $16.8 million for 2006 compared to 2005. The increase in interest expense was primarily due to increased interest rates during 2006.

*Income (loss) from derivative contracts.* We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative contract gains or losses are determined by actual derivative contract settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by SFAS 133; therefore, fluctuations in the market value of the derivative contract is recognized in earnings during the current period. In 2005 and 2006 all of our derivative contracts were in the form of price floors. We had realized and unrealized losses of approximately $(139,000) and $(452,000), respectively in 2005, compared to realized, and unrealized income of $565,000 and $89,000 for the year ended December 31, 2006.

*Income from discontinued operations.* Income from discontinued operations was $12.8 million in 2005. There was no income from discontinued operations in 2006 or 2007. On February 28, 2005, Grey Wolf Exploration Inc. completed an IPO resulting in Abraxas substantially divesting itself of its investment in Grey Wolf. The operations of Grey Wolf, previously reported as a business segment, are reported as discontinued operations for all periods presented in the accompanying financial statements and the operating results are reflected separately from the results of continuing operations.

Income from discontinued operations for the period ended December 31, 2005 included a gain on the disposal of Grey Wolf of $17.3 million, net of non-cash income tax of $6.1 million, and a loss from operations, including debt retirement costs, of $4.4 million.

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**Liquidity and Capital Resources**

***General***. The natural gas and crude oil industry is a highly capital intensive and cyclical business. Our capital requirements are driven principally by our obligations to service debt and to fund the following costs:

- the development of existing properties, including drilling and completion costs of wells;
- acquisition of interests in additional natural gas and crude oil properties; and
- production and transportation facilities.

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to continue to grow the business through the development of existing properties and the acquisition of new properties.

Abraxas' sources of capital going forward will primarily be cash from operating activities, funding under its credit facility, distributions from the Partnership and if an appropriate opportunity presents itself, proceeds from the sale of properties. We may also seek equity capital although we may not be able to complete any equity financings on terms acceptable to us, if at all. The Partnership's principal sources of capital will be cash from operating activities, borrowings under the Partnership Credit Facility, and sales of debt or equity securities if available to it.

***Working Capital (Deficit)***. At December 31, 2007 our current assets of approximately $28.1 million exceeded our current liabilities of $17.2 million resulting in working capital of $10.9 million. This compares to a working capital deficit of $3.7 million as of December 31, 2006. Significant components of current liabilities as of December 31, 2007 consisted of trade payables of $7.4 million, revenues due third parties of $2.4 million, other accrued liabilities of $1.9 million and current derivative liabilities of $5.2 million.

***Capital Expenditures***. Capital expenditures related to our continuing operations in 2005, 2006 and 2007 were $35.4 million, $26.3 million and $26.9 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2007.

| | **Year Ended December 31,** | | |
|---|---|---|---|
| | **2005** | **2006** | **2007** |
| | ***(dollars in thousands)*** | | |
| Expenditure category: | | | |
| Exploration/Development | $ 34,991 | $ 26,117 | $ 16,793 |
| Acquisition | - | - | 10,000 |
| Facilities and other | 359 | 229 | 115 |
| Total | $ 35,350 | $ 26,346 | $ 26,908 |

During 2005, 2006 and 2007, capital expenditures were primarily for the development of existing properties and a deposit for the St. Mary property acquisition that closed in January 2008. We anticipate making capital expenditures for 2008 of $55 million, excluding the cost of the St. Mary property acquisition completed in January 2008. These anticipated expenditures are subject to adequate cash flow from operations and availability under our revolving credit facility. The Partnership anticipates making capital expenditures for 2008 of $20 million which will be used primarily for the development of its current properties. These anticipated expenditures are subject to adequate cash flow from operations, availability under Abraxas' and the Partnership's Credit Facilities and, in Abraxas' case, distributions of available cash from the Partnership. If these sources of funding do not prove to be sufficient, we may also issue additional shares of equity securities although we may not be able to complete equity financings on terms acceptable to us, if at all. Our ability to make all of our budgeted capital expenditures will also be subject to availability of drilling rigs and other field equipment and services. Our capital expenditures could also include expenditures for the acquisition of producing properties if such opportunities arise. As discussed in "Business–Recent Events," Abraxas Energy Partners and Abraxas Petroleum completed the acquisition of certain oil and gas

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properties on January 31, 2008. Additionally, the level of capital expenditures will vary during future periods depending on market conditions and other related economic factors. Should the prices of natural gas and crude oil continue to decline and if our costs of operations continue to increase as a result of the scarcity of drilling rigs or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditures budget. If we decrease our capital expenditures budget, we may not be able to offset natural gas and crude oil production volumes decreases caused by natural field declines and sales of producing properties, if any.

***Sources of Capital.*** The net funds provided by and/or used in each of the operating, investing and financing activities, related to continuing operations, are summarized in the following table and discussed in further detail below:

| | **Year Ended December 31,** | | |
|---|---|---|---|
| | **2005** | **2006** | **2007** |
| | ***(dollars in thousands)*** | | |
| Net cash provided by operating activities | $21,099 | $15,561 | $18,332 |
| Net cash used in investing activities | (35,350) | (14,102) | (26,908) |
| Net cash (used in) provided by financing activities | 14,877 ) | (1,458 ) | 27,469 |
| Total | $626 | $1 | $18,893 |

Operating activities for the year ended December 31, 2007 provided $18.3 million in cash compared to providing $15.6 million in the same period in 2006. Net income plus non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds. Financing activities provided $26.6 million for the year ended December 31, 2007 compared to using $1.5 million for the same period of 2006. Most of the funds provided in 2007 were proceeds from the issuance of common stock, proceeds from the sale of common units of the Partnership and proceeds from the Partnership's and Abraxas' credit facilities. In 2006, most of the funds used were for net reductions in long-term borrowings from our revolving line of credit. Investing activities used $27.5 million during the year ended December 31, 2007 compared to using $14.1 million for the same period of 2006. Investing activities in 2007 included $16.9 million for the development of our existing properties and $10 million for the St. Mary property acquisition that was completed in January 2008.

Operating activities for the year ended December 31, 2006 provided us with $15.5 million of cash. Expenditures in 2006 of approximately $26.3 primarily for the development of natural gas and crude oil properties offset by proceeds from the sale of oil and gas properties of $12.2 million. Financing activities used $1.5 million during 2006, of which $20.4 million was provided from long-term borrowing offset by $22.4 million of payments on long-term debt.

Operating activities for the year ended December 31, 2005 provided us with $21.1 million of cash. Expenditures in 2005 of approximately $35.4 were primarily for the development of natural gas and crude oil properties. Financing activities provided $14.9 million during 2005, of which $11.3 million was provided by a private placement of common stock, $28.4 million was provided from long-term borrowing offset by $25.3 million of payments on long-term debt.

Our cash flow from operations will also depend upon the volume of natural gas and crude oil that we produce. Unless we otherwise expand reserves, our production volumes may decline as reserves are

produced. For example, in 2006, Abraxas replaced only 7% of the reserves it produced. In 2007 we replaced 219% of the reserves we produced. In the future, if an appropriate opportunity presents itself, we may sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful, exploration and development activities, acquire additional producing properties or identify additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive natural gas or crude oil reservoirs will be found. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flow from operations, distributions from the Partnership and the amount that we are able to borrow under our credit facilities will also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 69% of Abraxas Petroleum's and 50% of the Partnership's total estimated proved reserves at December 31, 2007 were undeveloped. During 2007, we expended approximately $16.9 million for wells in South Texas and West Texas. We continue to perform general well maintenance and work-overs utilizing our own work-over rigs. In addition, approximately 20% of our Mcfe production for the year ended December 31, 2007 was from a single well in West Texas. If production from this well decreases, the volume of our production would also decrease which, in turn, would likely cause our cash flow from operations to decrease.

***Contractual Obligations.*** We are committed to making cash payments in the future on the following types of agreements:

- Long-term debt; and
- Operating leases for office facilities

We have no off-balance sheet debt or unrecorded obligations and we have not guaranteed the debt of any other party. Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2007.

| **Contractual Obligations (dollars in thousands)** | **Payments due in:** | | | | |
|---|---|---|---|---|---|
| | **Total** | **2008** | **2009-2010** | **2011-2012** | **Thereafter** |
| Long-term debt (1) | $45,900 | $— | $— | $ 45,900 | $ — |
| Interest on long-term debt (2) | 10,978 | 3,213 | 6,426 | 1,339 | — |
| Operating Leases (3) | 340 | 313 | 27 | — | — |
| Total | $57,218 | $3,526 | $6,453 | $ 47,239 | $ — |

(1) These amounts represent the balances outstanding under the Partnership revolving credit facility. These repayments assume that we will not draw down additional funds.
(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.
(3) Office lease obligations. The lease for office space expires in January 2009.

We maintain a reserve for cost associated with the retirement of tangible long-lived assets. At December 31, 2007 our reserve for these obligations totaled $1.0 million for which no contractual commitment exist. For additional information relating to this obligation, see Note 1 of Notes to Consolidated Financial Statements.

***Off-Balance Sheet Arrangements.*** At December 31, 2007, we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have or are reasonably likely to have a current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

***Contingencies.*** From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2007 we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

***Other obligations.*** We make and will continue to make substantial capital expenditures for the acquisition, exploration, development and production of crude oil and natural gas. In the past, we have funded our operations and capital expenditures primarily through cash flow from operations, sales of properties, sales of production payments and borrowings under our bank credit facilities and other sources. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion.

***Long-Term Indebtedness***

Long-term indebtedness consisted of the following:

| | **December 31, 2006** | **December 31, 2007** |
|---|---|---|
| Floating rate senior secured notes due 2009 | $ 125,000 | $ — |
| Senior secured revolving credit facility | 2,614 | — |
| Partnership credit facility | — | 45,900 |
| Credit facility | — | — |
| | 127,614 | 45,900 |
| Less current maturities | — | — |
| | $ 127,614 | $ 45,900 |

***Floating Rate Senior Secured Notes due 2009***. In October 2004, Abraxas issued $125 million in principal aggregate amount of Floating Rate Senior Secured Notes due 2009. Thenotes were refinanced and redeemed with the proceeds from the refinancing transactions consummated in May 2007.

***Senior Secured Revolving Credit Facility***. In October 2004, Abraxas entered into an agreement for a revolving credit facility having a maximum commitment of $15 million, which included a $2.5 million sub facility for letters of credit. This facility was refinanced and terminated in May 2007.

***New Abraxas Senior Secured Credit Facility.*** On June 27, 2007, Abraxas entered into a new senior secured revolving credit facility, which we refer to as the Credit Facility. The Credit Facility has a maximum commitment of $50 million. Availability under the Credit Facility is subject to a borrowing base. The borrowing base under the Credit Facility, which is currently $6.5 million, is determined semi-annually by the lenders based upon our reserve reports, one of which must be prepared by our independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of our proved reserves utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, may make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we may also request one redetermination during any six-month period between scheduled redeterminations. The lenders may also make a redetermination in connection with any sales of producing properties with a market value of 5% or more of our current borrowing base. Our borrowing base at December 31, 2007 of $6.5 million was determined based upon our reserves at December 31, 2006 after giving effect to the contribution of properties to the Partnership in May 2007. Our borrowing base can never exceed the $50.0 million maximum commitment amount. Outstanding amounts under the Credit Facility will bear interest at (a) the greater of reference rate announced from time to time by Société Générale, and (b) the Federal Funds Rate plus ½ of 1%, plus in each case, (c) 0.5% - 1.5% depending on utilization of the borrowing base, or, if Abraxas elects, at the London Interbank Offered Rate plus 1.5% - 2.5%, depending on the utilization of the borrowing base. Subject to earlier termination rights and events of default, the Credit Facility’s stated maturity date will be June 27, 2011. Interest will be payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances.

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Abraxas is permitted to terminate the Credit Facility, and may, from time to time, permanently reduce the lenders' aggregate commitment under the Credit Facility in compliance with certain notice and dollar increment requirements.

Each of Abraxas' subsidiaries other than the Partnership, Abraxas General Partner, LLC and Abraxas Energy Investments, LLC has guaranteed Abraxas' obligations under the Credit Facility on a senior secured basis. Obligations under the Credit Facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of Abraxas' and the subsidiary guarantors' material property and assets.

Under the Credit Facility, Abraxas is subject to customary covenants, including certain financial covenants and reporting requirements. The Credit Facility requires Abraxas to maintain a minimum current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio (generally defined as the ratio of consolidated EBITDA to consolidated interest expense as of the last day of such quarter) of not less than 2.50 to 1.00.

In addition to the foregoing and other customary covenants, the Credit Facility contains a number of covenants that, among other things, will restrict Abraxas' ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an "arms-length" basis;
- make any change in the principal nature of its business; and
- permit a change of control.

The Credit Facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

***Amended and Restated Partnership Credit Facility.*** On May 25, 2007, the Partnership entered into a senior secured revolving credit facility which was amended and restated on January 31, 2008, which we refer to as the Partnership Credit Facility. The Partnership Credit Facility has a maximum commitment of $300.0 million. Availability under the Partnership Credit Facility is subject to a borrowing base. The borrowing base under the Partnership Credit Facility, which is currently $140.0 million, is determined semi-annually by the lenders based upon the Partnership's reserve reports, one of which must be prepared by the Partnership's independent petroleum engineers and one of which may be prepared internally. The amount of the borrowing base is calculated by the lenders based upon their valuation of the Partnership's proved reserves utilizing these reserve reports and their own internal decisions. In addition, the lenders, in their sole discretion, may make one additional borrowing base redetermination during any six-month period between scheduled redeterminations. The lenders may also make a redetermination in connection with any sales of producing properties with a market value of 5% or more of the Partnership's current borrowing base. The Partnership's current borrowing base of $140.0 million was determined based upon its reserves at June 30, 2007 and the reserves attributable to the oil and gas properties acquired from St. Mary Land & Exploration Company on January 31, 2008. The borrowing base can never exceed the $300 million maximum commitment amount. Outstanding amounts under the Partnership Credit Facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale and (2) the Federal Funds Rate plus 0.5% plus in each case (b) .25% - 1.00%, depending on the utilization of the borrowing base or, if the Partnership elects, at the London Interbank Offered Rate plus 1.25% - 2.00%, depending on the utilization of the borrowing base. Subject to earlier termination rights and events of default, the Partnership Credit Facility's stated maturity date is January 31, 2013. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. The Partnership is permitted to terminate the Partnership Credit Facility, and under certain circumstances, may be required, from time to time, to permanently reduce the lenders' aggregate commitment under the Partnership Credit Facility.

Each of the general partner of the Partnership, Abraxas General Partner, LLC, which is a wholly-owned subsidiary of Abraxas and which we refer to as the GP, and Abraxas Operating, LLC, which is a

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wholly-owned subsidiary of the Partnership and which we refer to as the Operating Company, has guaranteed the Partnership's obligations under the Partnership Credit Facility on a senior secured basis. Obligations under the Partnership Credit Facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the property and assets of the GP, the Partnership and the Operating Company, other than the GP's general partner units in the Partnership.

Under the Partnership Credit Facility, the Partnership is subject to customary covenants, including certain financial covenants and reporting requirements. The Partnership Credit Facility requires the Partnership to maintain a minimum current ratio as of the last day of each quarter of 1.0 to 1.0 and an interest coverage ratio (defined as the ratio of consolidated EBITDA to consolidated interest expense) as of the last day of each quarter of not less than 2.50 to 1.00. The Partnership Credit Facility required it to enter into derivative contracts for specific volumes, which equated to approximately 85% of the estimated oil and gas production from its net proved developed producing reserves through December 31, 2011 (including the reserves attributable to the St. Mary properties). The Partnership entered into NYMEX-based fixed price commodity swaps on approximately 85% of its estimated oil and gas production from our estimated net proved developed producing reserves (including the reserves attributable to the St. Mary properties) through December 31, 2011.

Under the terms of the Partnership Credit Facility, the Partnership may make cash distributions if, after giving effect to such distributions, the Partnership is not in default under the Partnership Credit Facility and there is no borrowing base deficiency and provided that no such distribution shall be made using the proceeds of any advance unless the amount of the unused portion of the amount then available under the Partnership Credit Facility is greater than or equal to 10% of the lesser of the Partnership's borrowing base (which is currently $140.0 million) or the total commitment amount of the Partnership Credit Facility (which is currently $300.0 million) at such time.

In addition to the foregoing and other customary covenants, the Partnership Credit Facility contains a number of covenants that, among other things, will restrict the Partnership's ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates;
- make any change in the principal nature of its business; and
- permit a change of control.

The Partnership Credit Facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness including the Subordinated Credit Agreement described below, bankruptcy and material judgments and liabilities.

***Subordinated Credit Agreement***

On January 31, 2008, the Partnership entered into a subordinated credit agreement which we refer to as the Subordinated Credit Agreement. The Subordinated Credit Agreement has a maximum commitment of $50 million, all of which was borrowed at closing. Outstanding amounts under the Subordinated Credit Agreement bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale and (2) the Federal Funds Rate plus 0.5% plus in each case (b) 4.00% to 5.50% depending on the applicable date or, if the Partnership elects, at the London Interbank Offered Rate plus 5.00% to 6.50% depending on the applicable date. The rates for the applicable dates are as follows:

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| Date | Eurodollar Rate (LIBOR) Advances | Base Rate Advances |
|---|---|---|
| 01/31/08 – 04/30/08 | 5.0% | 4.0% |
| 05/01/08 – 07/31/08 | 5.5% | 4.5% |
| After 07/31/08 | 6.5% | 5.5% |

Subject to earlier termination rights and events of default, the Subordinated Credit Agreement's stated maturity date is January 31, 2009. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. The Partnership is permitted to terminate the Subordinated Credit Agreement, and under certain circumstances, may be required, from time to time, to make prepayments under the Subordinated Credit Agreement.

Each of the GP and the Operating Company has guaranteed the Partnership's obligations under the Subordinated Credit Agreement on a subordinated secured basis. Obligations under the Subordinated Credit Agreement are secured by subordinated security interests, subject to certain permitted encumbrances, in all of the property and assets of the Partnership, GP, and the Operating Company, other than the GP's general partner units in the Partnership.

Under the Subordinated Credit Agreement, the Partnership is subject to customary covenants, including certain financial covenants and reporting requirements. The Subordinated Credit Agreement requires the Partnership to maintain a minimum current ratio as of the last day of each quarter of 1.0 to 1.0 and an interest coverage ratio (defined as the ratio of consolidated EBITDA to consolidated interest expense) as of the last day of each quarter of not less than 2.50 to 1.00. The Partnership Credit Facility required it to enter into derivative contracts for specific volumes, which equated to approximately 85% of the estimated oil and gas production from its net proved developed producing reserves through December 31, 2011 (including the reserves attributable to the St. Mary properties). The Partnership entered into NYMEX-based fixed price commodity swaps on approximately 85% of its estimated oil and gas production from our estimated net proved developed producing reserves (including the reserves attributable to the St. Mary properties) through December 31, 2011.

In addition to the foregoing and other customary covenants, the Subordinated Credit Agreement contains a number of covenants that, among other things, will restrict the Partnership's ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates;
- make any change in the principal nature of its business; and
- permit a change of control.

The Subordinated Credit Agreement also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness including the Credit Facility, bankruptcy and material judgments and liabilities.

***Hedging Activities***

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other

commodity derivative instruments. Under the terms of the Partnership Credit Facility, Abraxas Energy Partners was required to enter into hedging arrangements for specified volumes, which equated to approximately 85% of the estimated oil and gas production through December 31, 2011 from its net proved developed producing reserves. See "—Quantitative and Qualitative Disclosures about Market Risk—Hedging Sensitivity" for further information.

***Net Operating Loss Carryforwards***

At December 31, 2007, we had, subject to the limitation discussed below, $178.1 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2027 if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under FASB Statement No. 109. Therefore, we have established a valuation allowance of $66.9 million and $47.2million for deferred tax assets at December 31, 2006 and 2007, respectively.

***Related Party Transactions***

Abraxas has adopted a policy that transactions between Abraxas and its officers, directors, principal stockholders, or affiliates of any of them, will be on terms no less favorable to Abraxas than can be obtained on an arm's length basis in transactions with third parties and must be approved by the vote of at least a majority of the disinterested directors.

**Critical Accounting Policies**

The preparation of financial statements in conformity with generally accepted accounting principles requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following represents those policies that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

***Full Cost Method of Accounting for Natural Gas and Crude Oil activities***. SEC Regulation S-X defines the financial accounting and reporting standards for companies engaged in natural gas and crude oil activities. Two methods are prescribed: the successful efforts method and the full cost method. We have chosen to follow the full cost method under which all costs associated with property acquisition, exploration and development are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of natural gas and crude oil properties are generally calculated on a well by well or lease or field basis versus the "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of natural gas and crude oil properties under the successful efforts method. As a result our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization rate on our natural gas and crude oil properties.

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. We have experienced this situation several times over the years, most recently in 2002. Our natural gas and crude oil reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from the full cost method of accounting.

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 on a pool by pool basis, discounted at 10%, plus the lower of cost or fair market value of

unproved properties and the cost of properties not being amortized, less income taxes. 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 reported 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 depressed or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or if purchasers cancel long-term contracts for our natural gas production. 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 apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented.

***Estimates of Proved Natural Gas and Crude Oil Reserves.*** Estimates of our proved reserves included in this report are prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) and SEC guidelines. The accuracy of a reserve estimate is a function of:

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

Our proved reserve information included in this report was based on evaluations prepared by independent petroleum engineers. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

The estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields.

***Asset Retirement Obligations.*** The estimated costs of restoration and removal of facilities are accrued. The fair value of a liability for an asset’s retirement obligation is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense.

Accounting for Derivatives. From time to time, we use commodity price derivative contracts to limit our exposure to fluctuations in natural gas and crude oil prices. Fluctuations in the market value are recognized in earnings in the current period. Statement of Financial Accounting Standards, ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities", was effective for us on January 1, 2001. SFAS 133, as amended and interpreted, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. We have elected out of hedge accounting as prescribed by SFAS 133 - accordingly all of our derivative contracts are required to be recorded at fair value on our balance sheet, while changes in the fair value of our derivative contracts arel be recognized in earnings in the current period.

Due to the volatility of natural gas and crude oil prices and, to a lesser extent, interest rates, our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31,

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2006 and 2007, the net market value of our derivatives was an asset of $75,817 and a liability of $9.1 million, respectively.

***Share-Based Payments.*** We currently utilize a standard option pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees and directors. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. For the years ended December 31, 2005, 2006 and 2007, stock based compensation was approximately $247,000; $998,000 and $996,000 respectively.

**New Accounting Pronouncements**

***Fair Value Measurements (SFAS No. 157) —*** In September 2006, the FASB issued SFAS No. 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. SFAS No. 157 also emphasizes that fair value is a market-based measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The FASB agreed to defer the effective date of Statement 157 for one year for nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. There is no deferral for financial assets and financial liabilities. We are evaluating the impact of SFAS No. 157 on the consolidated financial statements and do not expect the impact of implementation to be material.

***The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115 (SFAS No. 159) —*** In February 2007, the FASB issued SFAS No. 159, which provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses on items, for which the fair value option has been elected, in earnings at each subsequent reporting date. This statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. This statement is effective for fiscal years beginning after November 15, 2007. We do not expect the implementation of SFAS No. 159 to have a material impact on our consolidated financial statements.

***Business Combinations (SFAS No. 141 (revised 2007)) —*** In December 2007, the FASB issued SFAS No. 141R, which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity's fiscal year that begins on or after December 15, 2008. We are evaluating the impact of SFAS No. 141R on our consolidated financial statements for any potential business combinations subsequent to January 1, 2009.

***Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51(SFAS No. 160) —*** In December 2007, the FASB issued SFAS No. 160, which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent's equity; the amount of consolidated net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently. This statement is effective for fiscal years beginning on or after December 15, 2008. We are evaluating the impact of SFAS No. 160 on our consolidated financial statements.

**Item 7A. Quantitative and Qualitative Disclosures about Market Risk**

**Commodity Price Risk**

As an independent natural gas and crude oil producer, our revenue, cash flow from operations, other income and equity earnings and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of crude oil, natural gas and natural gas liquids. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of natural gas and crude oil that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global political and economic conditions. Historically, prices received for natural gas and crude oil production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the year ended December 31, 2007, a 10% decline in natural gas and crude oil, prices would have reduced our operating revenue and cash flow by approximately $5.1 million for the year.

***Hedging Activity and Sensitivity***

To achieve more predictable cash flow, we reduce our exposure to fluctuations in the prices of oil and gas. We have and may continue to enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production. The Partnership credit facility required the Partnership to enter into hedging arrangements on specified volumes, which equated to approximately 85% of the projected oil and gas production from its pro forma net proved developed producing reserves through December 31, 2011. The Partnership has entered into NYMEX-based fixed price commodity swaps on approximately 85% of its estimated oil and gas production from our estimated pro forma net proved developed producing reserves through December 31, 2011 at volume weighted average prices of $84.54 per barrel of oil and $8.32 per MMbtu of gas.

We adopted SFAS 133 as amended by SFAS 137 and SFAS 138. Under SFAS 133, all derivative instruments are recorded on the balance sheet at fair value. We record our derivative instruments using the same method, accordingly the instruments are recorded on the balance sheet at fair value with

changes in the market value of the derivatives being recorded in current income.

At March 10, 2008, the Partnership had the following derivative contracts in place:

| Period Covered | Product | Volume (Production per day) | Fixed Price |
|---|---|---|---|
| Year 2008 | Natural Gas | 11,840 Mmbtu | $8.44 |
| Year 2008 | Crude Oil | 1,105 Bbl | $84.84 |
| Year 2009 | Natural Gas | 10,595 Mmbtu | $8.45 |
| Year 2009 | Crude Oil | 1,000 Bbl | $83.80 |

| | | | |
|---|---|---|---|
| Year 2010 | Natural Gas | 9,130 Mmbtu | $8.22 |
| Year 2010 | Crude Oil | 895 Bbl | $83.26 |
| Year 2011 | Natural Gas | 8,010 Mmbtu | $8.10 |
| Year 2011 | Crude Oil | 810 Bbl | $86.45 |

We expect to sustain realized and unrealized gains and losses as a result of these derivative contracts. For the year ended December 31, 2007, we recognized a realized gain of $1.9 million and an unrealized loss of $(6.3) million, and for the three months ended March 31, 2008, we recognized a realized loss of $(10.9) million and an unrealized loss of $(29.6) million on our derivative contracts. The losses for the year ended December 31, 2007 were the result of the contract prices for crude oil being significantly less than current market prices. On December 31, 2007, NYMEX futures prices were $96.01 per barrel of oil. We expect to continue to sustain realized and unrealized losses on our derivative contracts if market prices continue to be greater than our contract prices.

**Interest rate risk**

At December 31, 2007, we had $45.9 million in outstanding indebtedness under the Partnership Credit Facility. Outstanding amounts under the Partnership Credit Facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, and (2) the Federal Funds Rate plus 0.5%, plus in each case, (b) 0.25% to 1.25% depending on utilization of the borrowing base, or, if the Partnership elects, at the London Interbank Offered Rate plus 1.25% to 2.25%, depending on the utilization of the borrowing base. At December 31, 2007, the interest rate on the facility was 7.00%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $459,000 on an annual basis.

## Item 8. Financial Statements and Supplementary Data

For the financial statements and supplementary data required by this Item 8, see the Index to Consolidated Financial Statements.

## Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

## Item 9A. Controls and Procedures

**Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures**

Under the supervision and with the participation of our management, including our Chief Executive Officer (our principal executive officer) and our Chief Financial Officer (our principal financial officer), we evaluated the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”)). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer believe that the disclosure controls and procedures as of December 31, 2007 were effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms and are effective to ensure that information required to be disclosed by us is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

**Management’s Annual Report on Internal Control Over Financial Reporting**

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company’s principal executive and principal financial officers and implemented by the Company’s Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company’s assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by BDO Seidman LLP, an independent registered public accounting firm, as stated in their report which is included herein.

**Changes in Internal Controls**

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2007 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

**Item 9B. Other Information**

None.

**PART II**

**Item 10. Directors, Executive Officers and Corporate Governance**
There is incorporated in this Item 10 by reference that portion of our definitive proxy statement for the 2008 Annual Meeting of Stockholders which appears therein under the caption "Election of Directors – Board of Directors and Executive Officers," "– Code of Ethics" and "– Committees of the Board of Directors."

**Audit Committee and Audit Committee Financial Expert**

The Audit Committee of our board of directors consists of C. Scott Bartlett, Jr., Franklin A. Burke and Paul A. Powell. The board of directors has determined that each of the members of the Audit Committee is independent as determined in accordance with the listing standards of the American Stock Exchange and Item 407(a) of Regulation S-K. In addition, the board of directors has determined that C. Scott Bartlett, Jr., as defined by SEC rules, is an audit committee financial expert.

**Section 16(a) Compliance**

Section 16(a) of the Exchange Act requires Abraxas directors and executive officers and persons who own more than 10% of a registered class of Abraxas equity securities to file with the Securities and Exchange Commission and the AMEX initial reports of ownership and reports of changes in ownership of Abraxas common stock. Officers, directors and greater than 10% stockholders are required by SEC regulations to furnish us with copies of all such forms they file. Based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required. We believe that all our directors and executive officers complied on a timely basis with all applicable filing requirements under Section 16(a) of the Exchange Act during 2007.

**Item 11. Executive Compensation**
There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2008 Annual Meeting of Stockholders which appears therein under the captions "Election of Directors – Committees of the Board of Directors" and "Executive Compensation", except the material under the caption "Compensation Committee Report on Executive Compensation."

**Item 12.Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters**

There is incorporated in this Item 12 by reference that portion of our definitive proxy statement for the 2008 Annual Meeting of Stockholders which appears therein under the caption "Securities Holdings of Principal Stockholders, Directors, Nominees and Officers."

**Item 13. Certain Relationships and Related Transactions, and Director Independence**
There is incorporated in this Item 13 by reference that portion of our definitive proxy statement for the 2008 Annual Meeting of Stockholders which appears therein under the captions "Certain Transactions" and "Election of Directors – Board Independence."

**Item 14. Principal Accountants Fees and Services**
There is incorporated in this Item 14 by reference that portion of our definitive proxy statement for the 2008 Annual Meeting of Stockholders which appears therein under the caption "Principal Auditor Fees and Services."

**PART IV**

**Item 15. Exhibits, Financial Statement Schedules**

(a)1. Consolidated Financial Statements



(a) Financial Statement Schedules
2.
All schedules have been omitted because they are not applicable, not required under the instructions or the information requested is set forth in the consolidated financial statements or related notes thereto.

(a)3. Exhibits
The following Exhibits have previously been filed by the Registrant or are included following the Index to Exhibits.

| Exhibit Number. | Description |
|---|---|
| 3.1 | Articles of Incorporation of Abraxas. (Filed as Exhibit 3.1 to our Registration Statement on Form S-4, No. 33-36565 (the "S-4 Registration Statement")). |
| 3.2 | Articles of Amendment to the Articles of Incorporation of Abraxas dated October 22, 1990. (Filed as Exhibit 3.3 to the S-4 Registration Statement). |
| 3.3 | Articles of Amendment to the Articles of Incorporation of Abraxas dated December 18, 1990. (Filed as Exhibit 3.4 to the S-4 Registration Statement). |
| 3.4 | Articles of Amendment to the Articles of Incorporation of Abraxas dated June 8, 1995. (Filed as Exhibit 3.4 to our Registration Statement on Form S-3, No. 333-00398 (the "S-3 Registration Statement")). |
| 3.5 | Articles of Amendment to the Articles of Incorporation of Abraxas dated as of August 12, 2000. (Filed as Exhibit 3.5 to our Annual Report on Form 10-K (Filed April 2, 2001). |
| 3.6 | Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.6 to Abraxas' Annual Report on Form 10-K. (Filed April 5, 2002). |
| 4.1 | Specimen Common Stock Certificate of Abraxas. (Filed as Exhibit 4.1 to the S-4 Registration Statement). |

| | |
|---|---|
| 4.2 | Specimen Preferred Stock Certificate of Abraxas. (Filed as Exhibit 4.2 to our Annual Report on Form 10-K filed on March 31, 1995). |

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|---|---|
| *10.1 | Abraxas Petroleum Corporation 401(k) Profit Sharing Plan. (Filed as Exhibit 10.4 to Abraxas' Registration Statement on Form S-4, No. 333-18673, (the "1996 Exchange Offer Registration Statement")). |
| *10.2 | Abraxas Petroleum Corporation Amended and Restated 1994 Long Term Incentive Plan. (Filed as Exhibit 10.4 to Abraxas' Registration Statement on Form S-4 filed on January 12, 2005). |
| *10.3 | Form of Indemnity Agreement between Abraxas and each of its directors and officers. (Filed as Exhibit 10.4 to our Annual Report on Form 10-K filed March 14, 2007). |
| *10.4 | Employment Agreement between Abraxas and Robert L. G. Watson. (Filed as Exhibit 10.19 to the Registration Statement on Form S-1, No. 333-95281 (the "2000 S-1 Registration Statement")). |
| *10.5 | Employment Agreement between Abraxas and Chris E. Williford. (Filed as Exhibit 10.20 to the 2000 S-1 Registration Statement). |
| *10.6 | Employment Agreement between Abraxas and Stephen T. Wendel. (Filed as Exhibit 10.26 to the Registration Statement on Form S-3, No. 333-127480 (the "S-3 Registration Statement")). |
| *10.7 | Employment Agreement between Abraxas and William H. Wallace. (Filed as Exhibit 10.27 to the S-3 Registration Statement). |
| *10.8 | Employment Agreement between Abraxas and Lee T. Billingsley. (Filed as Exhibit 10.28 to the S-3 Registration Statement). |
| *10.9 | Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed June 6, 2005). |
| *10.10 | Form of Stock Option Agreement under the Abraxas Petroleum Corporation 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed June 6, 2005). |
| *10.11 | Abraxas Petroleum Corporation Senior Management Incentive Bonus Plan 2006. (Filed as Exhibit 10 to Annual Report on Form 10-K filed March 22, 2006). |
| 10.12 | Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed on May 26, 2006). |
| 10.13 | Contribution, Conveyance and Assumption Agreement dated as of May 25, 2007 by and among Abraxas Petroleum Corporation, Abraxas Energy Partners, L.P., Abraxas General Partner, LLC, Abraxas Energy Investments, LLC and Abraxas Operating, LLC. (Filed as Exhibit 10. 1 to Abraxas' Current Report on Form 8-K filed May 31, 2007). |
| 10.14 | Purchase Agreement dated as of May 25, 2007, by and among Abraxas Petroleum Corporation, Abraxas Energy Partners, L.P., Abraxas General Partner, LLC, Abraxas Operating, LLC and the purchasers named therein. (Filed as Exhibit 10. 2 to Abraxas' Current Report on Form 8-K filed May 31, 2007). |
| 10.15 | Registration Rights Agreement dated as of May 25, 2007, by and among Abraxas Energy Partners, L.P. and the purchasers named therein. (Filed as Exhibit 10. 3 to Abraxas' Current Report on Form 8-K filed May 31, 2007). |
| 10.16 | Omnibus Agreement dated as of May 25, 2007, by and among Abraxas Petroleum Corporation, Abraxas Energy Partners, L.P., Abraxas General Partner, LLC and Abraxas Operating, LLC. (Filed as Exhibit 10. 4 to Abraxas' Current Report on Form 8-K filed May 31, 2007). |
| 10.17 | Second Amended and Restated Agreement of Limited Partnership of Abraxas Energy Partners, L.P. (Filed herewith) |
| 10.18 | Securities Purchase Agreement dated May 25, 2007 by and among Abraxas Petroleum Corporation and the purchasers named therein. (Filed as Exhibit 10.7 to Abraxas' Current Report on Form 8-K filed May 31, 2007). |
| 10.19 | Form of Common Stock Purchase Warrant. (Filed as Exhibit 10. 8 to Abraxas' Current Report on Form 8-K filed May 31, 2007). |

10.20 Exchange and Registration Rights Agreement dated as of May 25, 2007 by and among Abraxas Petroleum Corporation, Abraxas Energy Partners, L.P. and the purchasers named therein. (Filed as Exhibit 10. 9 to Abraxas' Current Report on Form 8-K filed May 31, 2007).

10.21 Credit Agreement dated June 27, 2007 among Abraxas Petroleum Corporation, the lenders party thereto and Société Générale as Administrative Agent and Issuing Lender. (Filed as Exhibit 10.1 to Abraxas Current Report on Form 8-K filed June 28, 2007).

10.22 Amended and Restated Credit Agreement dated January 31, 2008 among Abraxas Energy Partners, L.P., the lenders party thereto, Société Générale as Administrative Agent and Issuing Lender, The Royal Bank of Canada, as Syndication Agent, and The Royal Bank of Scotland PLC, as Documentation Agent. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed on February 6, 2008).

10.23 Subordinated Credit Agreement dated January 31, 2008 among Abraxas Energy Partners, L.P., the lenders party thereto, Société Générale, as Administrative Agent, and The Royal Bank of Canada, as Syndication Agent. (Filed as Exhibit 10.3 to Abraxas' Current Report on Form 8-K filed on February 6, 2008).

10.24 Intercreditor and Subordination Agreement dated January 31, 2008 among Abraxas Energy Partners, L.P., the Senior Lenders party thereto, the Subordinated Lenders party thereto and Société Générale, as Administrative Agent. (Filed as Exhibit 10.4 to Abraxas' Current Report on Form 8-K filed on February 6, 2008).

10.25 Form of Indemnification Agreement by and among Abraxas Energy Partners, L.P., Abraxas General Partner, LLC, and each of its officers and directors (Filed herewith).

14.1 Abraxas Petroleum Corporation Code of Business Conduct and Ethics. (Filed as Exhibit 14.1 to Abraxas Annual Report on Form 10-K filed March 22, 2006).

18.1 Change in Accounting Principles.

21.1 Subsidiaries of Abraxas. (Filed herewith).

23.1 Consent of BDO Seidman, LLP. (Filed herewith).

23.2 Consent of DeGolyer and MacNaughton. (Filed herewith).

31.1 Certification – Chief Executive Officer. (Filed herewith).

31.2 Certification – Chief Financial Officer. (Filed herewith).

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

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

* Management Compensatory Plan or Agreement.

**Exhibit Index**

| | |
|---|---|
| 10.17 | Second Amended and Restated Agreement of Limited Partnership of Abraxas Energy Partners, L.P. (Filed herewith). |
| 10.25 | Form of Indemnification Agreement by and among Abraxas Energy Partners, L.P., Abraxas General Partner, LLC, and each of its officers and directors (Filed herewith). |
| 21.1 | Subsidiaries of Abraxas Petroleum Corporation. (Filed herewith). |
| 23.1 | Consent of BDO Seidman, LLP. (Filed herewith). |
| 23.2 | Consent of DeGolyer and MacNaughton. (Filed herewith). |
| 31.1 | Certification – Chief Executive Officer. (Filed herewith). |
| 31.2 | Certification – Chief Financial Officer. (Filed herewith). |
| 32.1 | Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith). |
| 32.2 | Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith). |

SIGNATURES

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

ABRAXAS PETROLEUM CORPORATION

| | |
|---|---|
| By: /s/ Robert L.G. Watson<br>President and Principal<br>Executive Officer | By: /s/ Chris E. Williford<br>Exec. Vice President and<br>Principal Financial and<br>Accounting Officer |

DATED: August 11, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

| Signature | Name and Title | Date |
|---|---|---|
| /s/ Robert L.G. Watson<br>Robert L.G. Watson | Chairman of the Board,<br>President (Principal Executive Officer)<br>and Director | August 11, 2008 |
| /s/ Chris E. Williford<br>Chris E. Williford | Exec. Vice President and<br>Treasurer (Principal Financial<br>and Accounting Officer) | August 11, 2008 |
| /s/ Craig S. Bartlett, Jr.<br>Craig S. Bartlett, Jr. | Director | August 11, 2008 |
| /s/ Franklin A. Burke<br>Franklin A. Burke | Director | August 11, 2008 |
| /s/ Harold D. Carter<br>Harold D. Carter | Director | August 11, 2008 |

| | | |
|---|---|---|
| /s/ Ralph F. Cox<br>Ralph F. Cox | Director | August 11, 2008 |
| /s/ Barry J. Galt<br>Barry J. Galt | Director | August 11, 2008 |
| /s/ Dennis E. Logue<br>Dennis E Logue | Director | August 11, 2008 |
| /s/ Paul Powell<br>Paul Powell | Director | August 11, 2008 |

**INDEX TO CONSOLIDATED FINANCIAL STATEMENTS**



All schedules are omitted because they are not required, are not applicable or the information required is included in the Consolidated Financial Statements or the notes thereto.

**Report of Independent Registered Public Accounting Firm**

Board of Directors and Stockholders

Abraxas Petroleum Corporation

San Antonio, Texas

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation as of December 31, 2007 and 2006 and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Abraxas Petroleum Corporation at December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007**,** in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Abraxas Petroleum Corporation's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 17, 2008 expressed an unqualified opinion thereon.

As discussed in Note 16 to the financial statements, the Company changed its classification of derivative instruments not designated as hedges in 2007.

Dallas, Texas

&LT/R&GT

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**Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting**

Board of Directors and Stockholders

Abraxas Petroleum Corporation

San Antonio, Texas

We have audited Abraxas Petroleum Corporation’s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Abraxas Petroleum Corporation’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A, “Management’s Report on Internal Control Over Financial Reporting”. Our responsibility is to express an opinion on the company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Abraxas Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Abraxas Petroleum Corporation as of December 31, 2006 and 2007, and the related consolidated statements of operations, stockholders’ equity (deficit), comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2007 and our report dated March 17, 2008 expressed an unqualified opinion thereon.

BDO Seidman, LLP

Dallas, Texas

March 17, 2008

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

| | December 31, 2006 | 2007 |
|---|---|---|
| | (Dollars in thousands) | |
| Current assets: | | |
| Cash and cash equivalents | $ 43 | $ 18,936 |
| Accounts receivable: | | |
| Joint owners | 556 | 840 |
| Oil and gas production sales | 5,645 | 5,288 |
| Other | 39 | — |
| | 6,240 | 6,128 |
| Derivative asset – Current | 157 | 2,658 |
| Other current assets | 313 | 377 |
| Total current assets | 6,753 | 28,099 |
| Property and equipment: | | |
| Oil and gas properties, full cost method of accounting: | | |
| Proved | 347,245 | 265,090 |
| Unproved properties excluded from depletion | — | — |
| Other property and equipment | 3,519 | 3,633 |
| Total | 350,764 | 268,723 |
| Less accumulated depreciation, depletion, and amortization | 246,353 | 151,696 |
| Total property and equipment - net | 104,411 | 117,027 |
| Deferred financing fees, net | 4,446 | 856 |
| Derivative asset – Long-term | — | 359 |
| Other assets including marketable securities | 1,330 | 778 |
| Total assets | $ 116,940 | $ 147,119 |

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (CONTINUED)

## LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

| | December 31, | |
|---|---|---|
| | **2006** | **2007** |
| | **(Dollars in thousands)** | |
| Current liabilities: | | |
| Accounts payable | $5,268 | $7,413 |
| Joint interest oil and gas production payable | 2,621 | 2,429 |
| Accrued interest | 1,427 | 241 |
| Other accrued expenses | 1,156 | 1,514 |
| Derivative liability – current | — | 5,154 |
| Total current liabilities | 10,472 | 16,751 |
| Long-term debt | 127,614 | 45,900 |
| Derivative liability – long-term | — | 3,941 |
| Future site restoration | 1,019 | 1,183 |
| Total liabilities | 139,105 | 67,775 |
| Minority interest | — | 23,497 |
| Commitments and contingencies | | |
| Stockholders' equity (deficit): | | |
| Common stock, par value $.01 per share – authorized 200,000,000 shares; issued 42,762,466 and 49,020,949 | 428 | 490 |
| Additional paid-in capital | 164,210 | 185,646 |
| Accumulated deficit | (187,493) | (130,791) |
| Treasury stock, at cost, 35,552 and -0- common shares | (285) | — |
| Accumulated other comprehensive income | 975 | 502 |
| Total stockholders' equity (deficit) | (22,165) | 55,847 |
| Total liabilities and stockholders' equity (deficit) | $116,940 | $147,119 |

See accompanying notes to consolidated financial statements

ABRAXAS PETROLEUM CORPORATION

## CONSOLIDATED STATEMENTS OF OPERATIONS

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2006 | 2007 |
| | (In thousands except per share data) | | |
| Revenues: | | | |
| Oil and gas production revenues | $ 47,905 | $ 49,448 | $ 46,906 |
| Rig revenues | 1,295 | 1,613 | 1,396 |
| Other | 16 | 16 | 7 |
| | 49,216 | 51,077 | 48,309 |
| Operating costs and expenses: | | | |
| Lease operating and production taxes | 11,094 | 11,776 | 11,254 |
| Depreciation, depletion, and amortization | 8,914 | 14,939 | 14,292 |
| Rig operations | 756 | 819 | 801 |
| General and administrative (including stock-based compensation of $247; $998; and $996) | 5,757 | 5,160 | 6,438 |
| | 26,521 | 32,694 | 32,785 |
| Operating income | 22,695 | 18,383 | 15,524 |
| Other (income) expense: | | | |
| Interest income | (19) | (29) | (408) |
| Amortization of deferred financing fees | 1,589 | 1,591 | 671 |
| Interest expense | 13,989 | 16,767 | 8,392 |
| Loss (gain) on derivative contracts (unrealized $452; $(81); and $6,288) | 591 | (646) | 4,363 |
| Loss on debt extinguishment | - | - | 6,455 |
| Gain on sale of assets | - | - | (59,439) |
| Other | 274 | - | 347 |
| | 16,424 | 17,683 | (39,619) |
| Income from continuing operations before income tax and minority interest | 6,271 | 700 | 55,143 |
| Income tax | - | - | (283) |
| Income from continuing operations before minority interest | 6,271 | 700 | 54,860 |
| Income from discontinued operations | 12,846 | - | - |
| Income before minority interest | 19,117 | 700 | 54,860 |
| Minority interest in loss of partnership | - | - | 1,842 |
| Net income | $ 19,117 | $ 700 | $ 56,702 |
| Basic earnings per common share: | | | |
| Continuing operations | $ 0.16 | $ 0.02 | $ 1.22 |
| Discontinued operations | 0.33 | - | - |
| Net income per common share - basic | $ 0.49 | $ 0.02 | $ 1.22 |
| Diluted earnings per common share: | | | |
| Continuing operations | $ 0.15 | $ 0.02 | $ 1.19 |
| Discontinued operations | 0.31 | - | - |
| Net income per common share - diluted | $ 0.46 | $ 0.02 | $ 1.19 |

See accompanying notes to consolidated financial statements

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ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)

(In thousands except number of shares)

| | **Common Stock** | | **Treasury Stock** | | | | **Accumulated** | |
|---|---|---|---|---|---|---|---|---|
| | | | | | **Additional** | | **Other** | |
| | | | | | **Paid-In** | **Accumulated** | **Comprehensive** | |
| | **Shares** | **Amount** | **Shares** | **Amount** | **Capital** | **Deficit** | **Income (loss)** | **Total** |
| Balance at December 31, 2004 | 36,597,045 | $ 366 | 105,989 | $ (549) | $ 150,961 | $ (207,310) | $ 3,068 | $ (53,464) |
| Net Income | — | — | — | — | — | 19,117 | — | 19,117 |
| Foreign currency translation adjustment | — | — | — | — | — | — | (3,068) | (3,068) |
| Change in unrealized gain (loss) fair value of investments | — | — | — | — | — | — | 1,684 | 1,684 |
| Stock-based compensation | — | — | — | — | 247 | — | — | 247 |
| Shares issued for compensation | — | — | (49,512) | 141 | (39) | — | — | 102 |
| Stock options exercised | 461,408 | 5 | — | — | 423 | — | — | 428 |
| Stock warrants exercised | 996,479 | 10 | — | — | (10) | — | — | — |
| Stock issued in private placement | 4,000,000 | 40 | — | — | 11,213 | — | — | 11,253 |
| Other | 8,235 | — | — | — | — | — | — | — |
| Balance at December 31, 2005 | 42,063,167 | 421 | 56,477 | (408) | 162,795 | (188,193) | 1,684 | $ (23,701) |
| Net Income – | — | — | — | — | — | 700 | — | 700 |
| Change in unrealized gain (loss) fair value of investments | — | — | — | — | — | — | (709) | (709) |
| Stock-based compensation | — | — | — | — | 998 | — | — | 998 |
| Shares issued for compensation | 5,782 | — | (20,925) | 123 | 14 | — | — | 137 |
| Stock options exercised | 693,517 | 7 | — | — | 403 | — | — | 410 |
| Balance at December 31, 2006 | 42,762,466 | 428 | 35,552 | (285) | 164,210 | (187,493) | 975 | $ (22,165) |
| Net Income – | — | — | — | — | — | 56,702 | — | 56,702 |
| Change in unrealized gain (loss) fair value of investments | — | — | — | — | — | — | (473) | (473) |
| Stock-based compensation | — | — | — | — | 996 | — | — | 996 |
| Shares issued for compensation | 22,960 | — | (35,552) | 285 | (94) | — | — | 191 |
| Stock options exercised | 208,109 | 2 | — | — | 10 | — | — | 12 |
| Equity issuance, net of offering costs | 5,874,678 | 59 | — | — | 20,525 | — | — | 20,584 |
| Restricted stock issue | 152,736 | 1 | — | — | (1) | — | — | — |
| Balance at December 31, 2007 | 49,020,949 | $ 490 | — | $ — | $ 185,646 | $ (130,791) | $ 502 | $ 55,847 |

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2006 | 2007 |
| | (In thousands) | | |
| **Operating Activities** | | | |
| Net income | $19,117 | $700 | $56,702 |
| Income from discontinued operations | 12,846 | — | — |
| Income from continuing operations | 6,271 | 700 | 56,702 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Minority interest in partnership loss | — | — | (1,842) |
| Gain on sale of partnership interest | — | — | (59,439) |
| Change in derivative fair value | 453 | (81) | 6,235 |
| Depreciation, depletion, and amortization | 8,914 | 14,939 | 14,292 |
| Accretion of future site restoration | 19 | 133 | 127 |
| Amortization of deferred financing fees | 1,589 | 1,591 | 671 |
| Stock-based compensation | 247 | 998 | 996 |
| Other non-cash transactions | — | 92 | 191 |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | (2,312) | 2,357 | 112 |
| Other assets and liabilities | 2,674 | (486) | 15 |
| Accounts payable | 5,230 | (5,406) | 1,063 |
| Accrued expenses | (1,986) | 724 | (791) |
| Net cash provided by continuing operations | 21,099 | 15,561 | 18,332 |
| Net cash used in discontinued operations | (4,132) | — | — |
| Net cash provided by operations | 16,967 | 15,561 | 18,332 |
| **Investing Activities** | | | |
| Capital expenditures, including purchases and development of properties | (35,350) | (26,346) | (26,908) |
| Proceeds from the sale of oil and gas properties | — | 12,244 | — |
| Net cash used in continuing operations | (35,350) | (14,102) | (26,908) |
| Net cash provided by discontinued operations | 25,671 | — | — |
| Net cash used in investing activities | (9,679) | (14,102) | (26,908) |
| **Financing Activities** | | | |
| Proceeds from issuance of common stock | 11,783 | 455 | 22,441 |
| Proceeds from issuance of partnership equity | — | — | 100,000 |
| Cost of common stock and partnership equity issuance | — | — | (9,098) |
| Proceeds from long-term borrowings | 28,374 | 20,444 | 46,690 |
| Payments on long-term borrowings | (25,272) | (22,357) | (128,404) |
| Partnership distribution to minority interest | — | — | (3,163) |

| | | | |
|---|---|---|---|
| Deferred financing fees | (8) | — | (997) |
| Net cash provided by (used in) continuing operations | 14,877 | (1,458) | 27,469 |
| Net cash used in discontinued operations | (23,407) | — | — |
| Net cash provided by (used in) financing activities | (8,530) | (1,458) | 27,469 |
| Increase (decrease) in cash | (1,242) | 1 | 18,893 |

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| | | | |
|---|---|---|---|
| Cash at beginning of year | 1,284 | 42 | 43 |
| Cash at end of year | $42 | $43 | $18,936 |

| | **Years Ended December 31,** | | |
|---|---|---|---|
| | **2005** | **2006** | **2007** |
| | **(In thousands)** | | |
| Supplemental disclosures of cash flow information: | | | |
| Interest paid | $16,575 | $12,583 | $9,494 |

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OTHER COMPREHENSIVE INCOME (LOSS)

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2006 | 2007 |
| | (In thousands) | | |
| Net income | $19,117 | $700 | $56,702 |
| Other Comprehensive income (loss): | | | |
| Reclassification of foreign currency translation adjustment relating to the sale of foreign subsidiary | (3,068) | — | — |
| Change in unrealized value of investments | 1,684 | (709) | (473) |
| Other comprehensive loss | (1,384) | (709) | (473) |
| Comprehensive income (loss) | $17,733 | $(9) | $56,229 |

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

**1. Organization and Significant Accounting Policies**

*Nature of Operations*

Abraxas Petroleum Corporation (”Abraxas” or “Abraxas Petroleum” or the “Company”) is an independent energy company primarily engaged in the exploration of and the acquisition, development, and production of crude oil and natural gas primarily along the Texas Gulf Coast, in the Permian Basin of western Texas and in Wyoming. The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries and its 47.2% interest in Abraxas Energy Partners, L.P. (the “Partnership”). All intercompany accounts and transactions have been eliminated in consolidation.

The terms “Abraxas” and “Abraxas Petroleum” refers only to Abraxas Petroleum Corporation, the term “Partnership” refers only to Abraxas Energy Partners L.P. and the terms “we,” “us,” “our,” or the “Company,” refer to Abraxas Petroleum Corporation, together with its consolidated subsidiaries including Abraxas Energy Partners, L.P., unless the context otherwise requires.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries through February 28, 2005. On February 28, 2005 our former wholly-owned subsidiary, Grey Wolf Exploration, Inc. closed an initial public offering, resulting in the substantial divestiture of our capital stock and operations in Grey Wolf. As a result of the disposal of Grey Wolf, the results of operations of Grey Wolf through February 28, 2005 are reflected in our consolidated financial statements as discontinued operations for all periods. For the period May 25, 2007 through December 31, 2007, the consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries as well as the operations of the Partnership which was formed on May 25, 2007, see note 3. The operations of Abraxas Petroleum and the Partnership are consolidated for financial reporting purposes. The interest of the 52.8% owners of the Partnership presented as minority interest. Abraxas owns the remaining 47.2% of the partnership interests. The Company has determined that based on its control of the general partner of the Partnership, this 47.2% owned entity should be consolidated for financial reporting purposes.

*Use of Estimates*

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Management believes that it is reasonably possible that estimates of proved crude oil and natural gas revenues could significantly change in the future.

*Concentration of Credit Risk*

Financial instruments, which potentially expose the Company to credit risk consist principally of trade receivables and crude oil and natural gas price derivative contracts. Accounts receivable are generally from companies with significant oil and gas marketing activities. The Company performs ongoing credit evaluations and, generally, requires no collateral from its customers.

The Company maintains its cash and cash equivalents in excess of Federally insured limits in prominent financial institutions considered by the Company to be of high credit quality.

*Cash and Equivalents*

Cash and cash equivalents include cash on hand, demand deposits and short-term investments with original maturities of three months or less.

*Accounts Receivable*

Accounts receivable are reported net of an allowance for doubtful accounts of approximately $10,000 at December 31, 2006 and 2007. The allowance for doubtful accounts is determined based on the Company's historical losses, as well as a review of certain accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

*Oil and Gas Properties*

The Company follows the full cost method of accounting for crude oil and natural gas properties. Under this method, all direct costs and certain indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized crude oil and natural gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of crude oil and natural gas properties, as adjusted for asset retirement obligations, less related deferred taxes, are limited to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10 percent, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. The Company does not have any properties that are being excluded from amortization. Costs in excess of the present value of estimated future net revenues as discussed above are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of crude oil and natural gas properties, except in unusual circumstances.

*Other Property and Equipment*

Other property and equipment are recorded on the basis of cost. Depreciation of other property and equipment is provided over the estimated useful lives using the straight-line method. Major renewals and betterments are recorded as additions to the property and equipment accounts. Repairs that do not improve or extend the useful lives of assets are expensed.

*Derivative Instruments and Hedging Activities*

The Company enters into agreements to hedge the risk of future crude oil and natural gas price fluctuations. Such agreements are primarily in the form of price floors, which limit the impact of price reductions with respect to the Company’s sale of crude oil and natural gas. The Company does not enter into speculative hedges.

Statement of Financial Accounting Standards, (“SFAS”) No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended and interpreted, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. The Company elected out of hedge accounting as prescribed by SFAS 133. Accordingly, all derivatives are recorded on the balance sheet at fair value with changes in fair value being recognized in earnings.

*Foreign Currency Translation*

The functional currency for Grey Wolf was the Canadian dollar ($CDN). The Company translated the functional currency into U.S. dollars ($US) based on the current exchange rate at the end of the period for the balance sheet and a weighted average rate for the period on the statement of operations. Prior to 2006, translation adjustments were reflected as accumulated other comprehensive income (loss), which is a component of stockholders' equity (deficit).

*Fair Value of Financial Instruments*

The Company includes fair value information in the notes to consolidated financial statements when the fair value of its financial instruments is materially different from the carrying value. The Company assumes the carrying value of those financial instruments that are classified as current approximates fair value because of the short maturity of these instruments. For noncurrent financial instruments, the Company uses quoted market prices or, to the extent that there are no available quoted market prices, market prices for similar instruments.

*Restoration, Removal and Environmental Liabilities*

The Company is subject to extensive Federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component are fixed or reliably determinable.

FASB Statement of Financial Accounting Standards No. 143*,* "Accounting for Asset Retirement Obligations" (SFAS 143) addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS 143 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense in the accompanying consolidated financial statements.

The following table summarizes the Company's asset retirement obligation transactions related to continuing operations during the following years ended December 31:

| | **2005** | **2006** | **2007** |
|---|---|---|---|
| | (in thousands) | | |
| Beginning asset retirement obligation | $ 888 | $ 883 | $ 1,019 |
| New wells placed on production and other | 115 | 29 | 43 |
| Deletions related to property disposals | (139) | (26) | (6) |
| Accretion expense | 19 | 133 | |